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Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington DC, 20005

**Re: Formal Case No. 1156**

Dear Ms. Westbrook-Sedgwick:

Enclosed, please find Comments of Potomac Electric Power Company on the Panel 1 and Panel 2 Questions for Technical Conference III in the above referenced proceeding.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Andrea H. Harper

Enclosures

cc: All Parties of Record

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

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| **IN THE MATTER OF** | ) | |
| | ) | |
| **The Application of Potomac Electric** | ) | |
| **Power Company for Authority** | ) | **Formal Case No. 1156** |
| **to Implement a Multiyear Rate Plan** | ) | |
| **for Electric Distribution Service** | ) | |
| **in the District of Columbia** | ) | |

# COMMENTS OF POTOMAC ELECTRIC POWER COMPANY ON THE PANEL 1 AND PANEL 2 QUESTIONS FOR TECHNICAL CONFERENCE III

In accordance with Paragraph 2 of the Technical Conference Notice ("Notice") issued by the Public Service Commission of the District of Columbia ("Commission") regarding Technical Conference III in this proceeding,[1] Potomac Electric Power Company ("Pepco") respectfully files its comments ("Comments") on the questions issued in the Notice and discussed in Panels 1 and 2 of Technical Conference III held on October 17 and 18, 2019, respectively.

These Comments are organized to track the questions the Commission included in the Notice for Technical Conference III. Part A addresses the seventeen questions relating to the potential risks and benefits of alternative forms of regulation that the Commission identified in the Notice for discussion by Panel 1. Part B responds to each of the twelve questions regarding what other states are experiencing in implementing alternative forms of regulation that the Commission identified in the Notice for Panel 2 at Technical Conference III. Pepco has attached to these comments (1) its Panel 1 presentation; (2) its Panel 2 presentation; (3) "Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates," prepared by The Brattle

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[1] The Notice was originally issued on September 18, 2019. The Commission issued an Amended Notice on September 26, 2019. Unless otherwise indicated, references in these Comments to the Notice refer to the Amended Notice.

Group; and (4) "Alternative Regulation for Emerging Utility Challenges: 2015 Update," prepared by the Edison Electric Institute.

## I. INTRODUCTION

Technical Conference III provided important and useful information as the Commission moves forward with the use of alternative ratemaking mechanisms. Combining the perspectives of the parties, state commissions that have already or are in the process of implementing alternative ratemaking mechanisms and Staff-invited organizations that had deep knowledge of alternative ratemaking, their impact within the industry and their impact outside of the industry created a fulsome record for use in implementing alternative regulation in the District of Columbia.

The participants in Technical Conference III demonstrated that alternative ratemaking is widely and successfully used around the country, and the number of states allowing alternative ratemaking grows every year. The Commission will be in good company when it adopts alternative ratemaking and can use the experiences of different states, including the participants in Technical Conference III, to inform its decision making. Technical Conference III also demonstrated that there was a general agreement among many of the participants. For example, the participants generally agree that alternative ratemaking is not new and that it is currently being used in numerous states. Participants also generally agreed that the burden of proof under alternative rate mechanisms should remain on the utility. Moreover, well-designed alternative ratemaking is beneficial to customers. Many participants showed that Multiyear Rate Plans ("MRPs") increase rate transparency, reduce regulatory lag, and reduce the frequency of rate cases. Finally, the participants demonstrated that performance incentive mechanisms ("PIMs") can provide incentives for utilities to improve their performance and align utility goals with jurisdictional policies and priorities.

With the information and lessons learned provided in Technical Conference III, the Commission has a sound basis to choose the alternative ratemaking mechanism(s) that will be used in the District of Columbia and a strong foundation for creating the framework for evaluating such mechanism(s).

## II. COMMENTS

### A. PANEL 1 COMMENTS

#### 1. What evidence should a public utility, as defined in D.C. Code § 34-214, present to support alternative forms of regulation proposals?

The Commission should primarily consider the existing laws regarding its selection of an appropriate type of alternative regulation mechanism. According to Section 34-1504(d) of the District of Columbia Official Code ("DC Code"), the standard for consideration of an alternative regulation mechanism is that it must (1) protect customers, (2) ensure the quality, availability and reliability of regulated electric services,[2] and (3) be in the interest of the public, including the interests of shareholders of the utility.[3]

Once the Commission selects an alternative regulation mechanism, the Commission should consider the following factors in its evaluation of a specific alternative regulation proposal: (1) are the resulting rates just and reasonable, (2) does the proposal support the District's energy and other

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2 AOBA's presenter recognized the importance of consistency with utility provision of safe and reliable service. AOBA Panel 1, Slide 5.

3 DC Code §34-1504(d)(1) expressly provides: "Notwithstanding any other provision of law, the Commission may regulate the regulated services of the electric company through alternative forms of regulation."

policy goals,[4] (3) does the proposal support the Commission's policy goals,[5] (4) does the proposal provide adequate customer protections, (5) does the proposal provide for a financially healthy utility,[6] and (6) does the proposal lower administrative and regulatory costs and burdens.

Public utilities in the District of Columbia should be able to support alternative ratemaking proposals in various ways. With respect to multiyear rate proposals ("MRPs"), public utilities should be permitted to choose among three options: (1) the utility could elect to submit evidence similar to that required in a traditional rate proceeding to support its costs and revenues over the years requested in the MRP, using internal corporate forecasts. (2) In the alternative, in situations where it is appropriate to use an escalation factor, the utility should be permitted to present evidence supporting an escalation factor to be applied to a traditional "base case" cost and revenue determination. In this alternative proposal, the utility should provide evidence supporting the escalation factor used. (3) Finally, the utility should be permitted to use a hybrid approach that combines forecasting in certain areas and using an escalation factor in other areas.

With respect to evidence supporting PIMs, public utilities should submit a clear description of the types of PIMs being proposed; a detailed rationale supporting each PIM, including the benefits to consumers; baseline data with respect to each PIM to permit an analysis of the utility's future performance; and clear metrics to determine whether the utility meets the goals of each PIM. The utility should also submit evidence supporting its proposals for revenue adjustments in the event that the utility exceeds or falls below the targets for the respective PIMs.

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4 OPC agrees that the proposal must support the District's energy and other policy goals. OPC Panel 1 Slide 9.

5 OPC agrees that the proposal must support the Commission's energy and other policy goals. OPC Panel 1 Slide 9.

6 AOBA's presenter (AOBA Panel, 1 Slide 5) and OPC's presenter (Panel 1, Slide 3) recognized the importance of the ongoing financial health of the utility.

2. **What are the benefits of any alternative forms of regulation, including performance-based ratemaking ("PBR") or MRP/PIM, relative to its costs/risks?**

As the presenter from The Regulatory Assistance Project ("RAP") discussed, "PBR is a powerful tool in the regulator's tool box."[7] MRPs, in particular, reduce the frequency of rate cases, which lowers the cost to customers and reduces the administrative burden on the Commission and stakeholders, as well as incentivizes the utility to be more efficient.[8] As a result, the Commission, the utility and intervenors will expend fewer resources on rate case proceedings under an MRP.

As many of the Technical Conference III presenters discussed, PBR and MRPs/PIMs are not new.[9] There are many states that have already adopted PBR and MRPs and are experiencing the benefits. In addition, more states, such as Hawaii and Maryland are beginning to adopt PBR and MRPs. Moreover, the Commission has previously indicated its willingness to consider alternative ratemaking methodologies. In Formal Case No. 1139, the Commission stated that it was "not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year or a multi-year rate proposal, in addition to a traditional test year filing…."[10] As benefits of different alternative rate methodologies may differ, Pepco is focusing on MRPs in its discussion of the benefits in these Comments.

PBR uses specific performance metrics, targets or incentives to influence utility performance in ways that support jurisdictional priorities.[11] MRPs/PIMs will improve the

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7 RAP Panel 1 Presentation, Slide 47.

8 Synapse Panel 1 Presentation, Slide 2.

9 For example, the presenter from EEI stated that neither alternative regulation nor MRPs are new. In fact, MRPs were first used in the railroad, oil and telecom industries decades ago.

10 *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Formal Case No. 1139, Order No. 18846 at ¶594 (July 27, 2017) ("Order No. 18846").

11 RAP Panel 1 Presentation, Slide 7.

alignment of utility performance with important District and Commission goals and facilitate investments that support the District's policies. As discussed by the RAP presenter, the benefits that flow from the improved performance ideally should be shared between the utility and its customers.[12] This helps create the fair distribution of risk between utilities and customers that the Hawaii Commission's presenter discussed.[13] As discussed by the District Government's presenter, MRPs also increase innovation by allowing the utility to manage business decisions with greater flexibility.

MRPs provide the Commission and stakeholders with a longer-term view of future capital investments and operation and maintenance ("O&M") costs, as the utility is required to submit information regarding its financial plans during the full MRP period. As the EEI presenter discussed, this longer-term view increases transparency and visibility into utility financial planning. Unlike a traditional rate case that relies on historical costs, the Commission and stakeholders are able to review the utility's financial plan in advance of the money being spent. The increased transparency leads to increased utility accountability and provides incentives for the utility to manage resources and administrative costs all of which benefit customers.

Moreover, MRPs provide customers with rate predictability not available under the traditional ratemaking process. As a result, customers are provided with critical rate information to assist them in their decision-making and planning processes. MRPs that include a reconciliation mechanism also provide customers with greater bill certainty than traditional ratemaking as they establish a clear schedule regarding the timing of bill changes. Moreover, adjustments resulting from the reconciliation process, which may increase or decrease bill changes, are subject to

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12 RAP Panel 1 Presentation, Slide 7.

13 Hawaii Commission Panel 2 Presentation, Slide 3.

Commission review and approval. Finally, if structured appropriately, such reconciliation adjustments would be more akin to a "fine tuning" of, rather than significant modifications to, the amount of bill changes and would serve to protect customers by ensuring that rates are reflective of the utility's actual experience.

An MRP proposal may improve the overall financial health of the utility, which ultimately lowers borrowing costs and rates and improves access to capital in the market, allowing the utility the ability to earn its approved return and eliminating "regulatory lag." As the presenter from Regulatory Research Associates ("RRA") discussed, investors view timely recovery of investments as constructive.[14] Under traditional ratemaking methodologies, the utility recovers the costs of such investments well after they are incurred—in many cases 12 to 24 months later—while under an MRP those costs can be recovered more timely. As a result, an MRP will reduce the number of rate cases a utility will be required to file to recover the costs of the investments essential to meet the District's goals.

As the Commission noted in Order No. 18846, "[m]ost multi-year rate plans feature a performance metric system that includes some performance incentive mechanisms ("PIM"). These PIMs provide awards or penalties, or both, for performance in targeted areas."[15] PIMs can improve specific areas of utility performance, providing targeted benefits to customers. However, to realize the benefits of PIMs, they must be structured properly using clearly defined and measurable performance criteria. Metrics[16] must be defined as well as outputs[17] and outcomes.[18]

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14 RRA Panel 2 Presentation, Slide 18.

15 Order No. 18846 at ¶595.

16 RAP Panel 1 Presentation, Slide 15.

17 RAP Panel 1 Presentation, Slide 16. According to the RAP presenter, "[o]utputs are specific results of utility actions, often measured as a measurable performance criteria or metrics."

18 RAP Panel 1 Presentation, Slides 16. According to the RAP presenter, "[o]utcomes are how utility services affect [customers] and society and are the desired results from a specific guiding goal, directional incentive and/or operational incentive."

**3. Under alternative ratemaking including MRP, how can the Commission assure ratepayers that they are paying only for prudent and efficient costs, and that the burden of proof remains with the public utility to show that a proposed rate change is just and reasonable?**

As evidenced during the technical conference, the participants agree that the Commission's level of oversight should remain the same regardless of the ratemaking plan adopted. The burden of proof would remain on the utility to justify its rate proposal and to demonstrate that the costs it seeks to recover through rates were prudently incurred.[19] Indeed, in the case of an MRP, the Commission's oversight ability is enhanced because the Commission receives a longer-term view of future capital and O&M investments before the utility makes the investments, increasing transparency. The Commission and parties have enhanced visibility into and an opportunity to review and discuss planned spend prior to the utility making system investments. The Commission retains jurisdiction to fully evaluate a utility's rate filing and to provide any necessary guidance regarding ratemaking initiatives.

In addition, the Commission's oversight ability is enhanced through the utility providing ongoing reporting as part of the MRP, as the utility would provide annual reconciliation filings. These filings will permit the Commission and interested parties to carefully review the utility's annual expenditures and costs and to allow them to review actual results versus projections. Material variances will be discussed by the utility. Such a reconciliation mechanism is required to provide additional insurance that the utility's rates remain just and reasonable and customer rates reflect the utility's investments. Reconciliations also will benefit customers "if a utility earns

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[19] For example, under the Company's proposed MRP, the prudency of costs incurred following the Commission's order approving the MRP would be addressed in conjunction with the Annual Reconciliation Filing.

a return higher than that authorized."[20] Any such proposal should also include a provision that would permit any party, or the Commission on its own motion, to propose to re-open and review the MRP if there is an issue that cannot be resolved in any other manner under the proposal (*e.g.*, new legislation adopted that materially decreases the utility's costs).

**4. What are the key decision factors (metrics or criteria) to be used to evaluate and select an alternative form of regulation which will balance the public utility's cost recovery (including whether a decoupling mechanism should be applied), earning sharing mechanism, incentives for the public utility to improve its targeted performance, rate impact, consumer interest, grid modernization, clean energy and environmental policies/goals, affordability and reliability goals to meet public interest? Are there additional goals for which performance incentives can be developed? Are such goals applicable only to electric utilities, natural gas utilities, or both?**

As discussed in response to Question 1, the Commission should primarily consider the existing laws regarding its selection of an appropriate type of alternative regulation mechanism. Specifically, the Commission should use DC Code §34-1504(d) as the standard for consideration of an alternative regulation mechanism. Moreover, once the Commission selects an alternative regulation mechanism, the Commission should consider the six factors discussed in response to Question 1 in its evaluation of a specific alternative regulation proposal.

Multiple states have implemented both alternative ratemaking, in the form of multiyear rate plans, and decoupling.[21] However, they address different goals and concerns. Revenue decoupling is designed to assist utilities, states, and consumers in meeting environmental and

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20 Maryland Commission Panel 2 Presentation, Slide 23.

21 States with multiyear rate plans and full decoupling include New York, Massachusetts, and Hawaii. States with multiyear rate plans and partial decoupling, typically limited to decreases in revenues due to energy efficiency, include Arizona, Ohio, and Washington. *See* Pacific Economics Group, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared for Edison Electric Institute, November 11, 2015; Regulatory Research Associates, "RRA Topical Special Report, Adjustment Clauses: A State-by-State Overview," August 22, 2016; Massachusetts Department of Public Utilities, "Order Establishing Eversource's Revenue Requirement," D.P.U. 17-05 (November 30, 2017).

market outcomes by de-linking utility revenue from the level of commodity sales made. In contrast, alternative ratemaking attempts to encourage utility efficiency and cost savings, while also addressing concerns with regulatory lag and use of resources for frequent rate cases. Thus, there is no reason why a utility cannot—and in the interests of meeting the District's climate initiatives should not—have a revenue decoupling mechanism and an alternative ratemaking mechanism in place simultaneously. As several presenters noted at Technical Conference III, several states allow both alternative ratemaking mechanisms and decoupling.

5. **What specific performance outcomes and targets by the public utility should be measured and reported, inclusive of those aligned with the District's clean energy goals, including effects on global climate change and the District's public climate commitments, and how should performance targets and outcomes be measured? Identify and discuss other areas of public utility performance that should be measured and reported to the Commission, why they should be measured and their importance to the public interest? Are such performance outcomes and targets applicable to electric utilities, natural gas utilities, or both?**

In January 2019, the District passed the CleanEnergy DC Omnibus Amendment Act of 2018[22] ("CleanEnergy DC Act") to spur integration of clean energy. Among many other objectives, the CleanEnergy DC Act sought to expand the District's renewable portfolio standard ("RPS") to 100% renewable electricity by 2032 and to reduce greenhouse gas ("GHG") emissions some 50% by 2032. The CleanEnergy DC Act also increased access to energy efficiency programs for low- and moderate-income residents, expanded solar energy in the District and expanded transportation GHG emissions reductions. There is general consensus among the stakeholders that participated in the technical conference regarding the importance of the District's energy goals.[23]

[22] DC Law 22-257, effective March 22, 2019.

[23] Indeed, the CleanEnergy DC Act expressly requires that the Commission in its supervision and regulation of utilities consider "the preservation of environmental quality, including effects on global climate change and the District's public climate commitments." D.C. Code §34-808.02.

The Commission built upon this progress with the issuance of its proposed order in PowerPath DC, in which it proposed, *inter alia*, the integration of more non-wire alternatives through Pepco's improved distribution system planning process; greater data access by customers and third parties; increased distributed energy resource deployment—including the need for demonstration projects; consolidated and enhanced customer education materials; development of energy efficiency programs for master metered apartments; and alternative technological advancements.

Moreover, the Commission separately approved a transportation electrification program that will allow Pepco to support the proliferation of transportation electrification in the District. Finally, the Commission has established the energy efficiency working group required by the CleanEnergy DC Act that will recommend long-term and annual energy savings metrics, quantitative performance indicators and cost-effective standards for utility energy efficiency and demand response programs.

These and other proceedings currently underway at the Commission will identify the specific performance outcomes and outputs to achieve the District and Commission policy goals. The outcomes and outputs from these and other Commission workstreams will help identify PIMs supporting District and Commission goals that the utility could reasonably influence and could be incorporated into an MRP in the future. This could include, for example, PIMs to incentivize efforts to meet or exceed certain energy efficiency goals. In addition, the Commission could approve the tracking of metrics that may be considered for PIMs in the future (*e.g.*, CEMI) until such time as there is enough data to properly structure and measure performance.

Many of these performance outcomes and outputs may not translate into dollar savings but will still provide customers significant benefits (*e.g.*, the utility reducing its GHG production) and advance District and Commission goals. If the District is to achieve its long-term energy and other policy goals, it is critical that outputs and outcomes not be measured on a dollar value alone.

6. **Besides the following key goals of utility regulation (traditional or performance-based) which include reasonable, affordable rates, reliable service, customer service and satisfaction, and environmental performance, please identify and discuss any additional key goals for the electric utilities for which performance metrics should be developed.**

As was noted previously, PIMs can be used to drive policy and incentivize utilities to perform at or above the target levels, in support of the District's and Commission's policies and goals. To be effective, PIMs should be measurable, and they should measure activities for which the utility is reasonably able to impact the outcome or output. For activities outside of the utility's ability to impact, the Commission should use tracking mechanisms rather than PIMs in order to gather data.

PIMs for future consideration may reflect reliability metrics, service level metrics, interconnection metrics, supplier diversity and local business engagement metrics, energy efficiency metrics, and metrics based on the utility's efforts to reduce the greenhouse gas emissions produced by its operations.

7. **Identify and discuss the extent to which those areas that are currently measured or evaluated either by public utilities or an independent third party and whether the current measurements or evaluations are sufficient to adequately evaluate the public utility's performance in those areas.**

Pepco and the Commission currently measure reliability, service level and abandonment rates, and certain aspects of interconnection of distributed energy resources. These metrics were developed through Electric Quality of Service Standards (*e.g.*, service level and abandonment rates), merger commitments (*e.g.*, SAIDI and SAIFI), and separate rulemakings and Commission order (*e.g.*, small generator interconnection standards). As the presenter for RAP discussed, customer service and reliability metrics help ensure that utility performance continues to be strong in light of cost management incentives in MRPs.[24] The Minnesota Public Utilities Commission adopted several reliability and customer service PIMs.[25] As the presenter from the Maryland Commission discussed, "[s]uperior performance by a utility results in increased profits, while inferior performance may lead to decreased profits."[26]

The Commission has recently revised its interconnection rules in a manner designed to challenge Pepco to meet the required deadlines for Approval to Install. Developing an emerging PIM that measures the utility performance on the new interconnection timeframes will provide the utility the incentive to more quickly to meet these new requirements. Moreover, while reliability, service level and abandonment rate are measured and evaluated by the Commission, the current EQSS measurements may be improved upon through the introduction of PIMs that reward or penalize the utility for performance.

**8. Discuss how each identified area of public utility performance should be measured and the extent to which each can be cost-effectively verified**

PIMs should be structured in a manner that is reflective of how a particular utility operates, as every company and jurisdiction is slightly different and what works in one instance may not be appropriate in another without modification. Additionally, the metrics selected for the PIM should permit the utility to communicate clearly to the Commission given the utilities existing operational standards. PIMs should be measured based on appropriate trackable standards that are within the utility's ability to impact, they should also incorporate a reasonable deadband. Finally, the metrics used to measure PIMs must be able to be cost effectively verified.

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24 RAP Panel 1 Presentation, Slide 32 and discussion.

25 *In the Matter of a Commission Investigation to Identify Performance Metrics and Potentially Incentives for Xcel Energy's Electric Utility Operation*, Docket No. E-002/CI-17-401, Order Establishing Performance Metrics (Sept. 18, 2019).

26 Panel 2 Maryland Commission Presentation Slide 13.

**9. Identify and discuss areas of performance that would be aided by a study of achievable potential needed to establish performance targets.**

As a general rule, Pepco is open to discussing performance metrics. If studies would add value to the process, Pepco would be open to them; however, the Company believes that not every performance target requires a study to develop the appropriate metrics. In some cases, the use of tracking metrics or pilots may be more appropriate. At present, Pepco does not have any specific studies that it believes are necessary.

**10. Should rate design (revenue requirement allocation to various customer classes) stay the same for all the rate years within an MRP? If not, what factors should the Commission consider in evaluating whether an alternative rate design proposal provides ratepayers with benefits that they do not receive under the traditional rate design?**

Any discrete change to rate design can be made in the context of either a traditional test period rate case or an MRP. In an MRP, rate design and class cost of service should remain the same throughout the term of the MRP. The rate design should be determined prior to the beginning of the MRP. The Commission should consider the same factors that it currently considers when evaluating rate design proposals. The class cost of service should be based on the traditional test period or historical data. The jurisdictional allocation, which represents costs allocated between multiple jurisdictions based on work activity, should be able to change from year to year based on the forecasted allocation. As discussed earlier, alternative regulation does not reduce the need for a decoupling mechanism, and several utilities have both mechanisms.

**11. If the alternative ratemaking is based on forecasted costs, what mechanisms and incentives should the Commission adopt that ensure effective review of forecast methodology and data inputs, ensure shifts in risk are appropriate and promote just and reasonable rates to end users?**

There are a number of mechanisms and/or incentives that the Commission could consider to ensure effective review of forecast methodology and data inputs. For instance, the Commission could require that the utility provide information regarding its budget and financial forecasting process, including narrative explanations of the process and specific data underlying the financial forecasts. The proposal should include a year's historical data to allow the Commission and parties a foundation from which to view the forecasted costs. To provide appropriate context for the costs, the proposal should provide a list of initiatives and the financial planning assumptions.

The Commission and parties should have the opportunity to review the forecasting methodology in an alternative ratemaking proceeding, such as an MRP proceeding, providing transparency into the financial planning and financial forecasting. The utility should provide annual reconciliation filings that show and, if material, explain variances between actual costs and forecasts. The annual reconciliation mechanism (or earnings sharing mechanism), particularly if coupled with other performance-based regulation in the form of PIMs, for example, will ensure the appropriate sharing of risk and ensure customer rates reflect the utility's investments. As recognized by District Government's presenter, earnings sharing mechanisms generally contain deadbands, within which no earnings are shared, thereby creating a strong incentive for the utility to operate efficiently. This risk and accountability for the reasonableness and prudence of expenditures continues to exist for MRPs with annual reconciliation mechanisms with a deadband. The long-term nature of the MRP structure promotes just and reasonable rates, provides known changes to bills for customers, and incentivizes utilities to invest in a manner that aligns with District and Commission policy goals.

**12. What parameters should be considered in the true-up or reconciliation process (annual, semi-annual, quarterly)? What is the best practice for such a process?**

Utility proposals should contain an annual reconciliation mechanism.[27] Annual reconciliations help streamline the regulatory process and improve administrative efficiencies. Annual reconciliations balance the need for customer protections and transparency with the administrative burden and cost of repeated filings. To achieve the appropriate balance, the annual reconciliation should not become a mini rate case examining all costs every year as this would be contrary to the Commission's goal of streamlining the process. Although parties can ask discovery on any items, the annual reconciliation filing review should focus on material variance to the MRP approved by the Commission. The time for challenging the MRP or other alternative rate proposal would be when the proposal is being litigated in the first instance. Instead, the annual reconciliation should include a variance report of actuals versus forecasted costs, and the utility should provide an explanation of material variances that exceed certain dollar and percentage thresholds. Variances below the designated thresholds should be deemed within budget. The parties should be given a period of discovery commensurate with the streamlined and then be afforded the opportunity to provide comments to which the utility should be able to reply. Then the Commission should issue an order.

**13. Should public utilities seeking alternative forms of regulation plans acknowledge that imprudently incurred costs during MRP will be subject to refund, and be required to waive any claim that such a decision would be barred as a form of retroactive ratemaking?**

If a cost is deemed imprudent by the Commission, it should not be recoverable, regardless of whether a traditional or an alternative form of regulation is used. An important aspect of an

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[27] OPC's presenter supports including "opportunities to evaluate whether the ARM is working as intended." The annual reconciliation provides that opportunity annually.

MRP that inures to the benefit of both the customer and the utility is an annual reconciliation mechanism. Such a mechanism can ensure the appropriate sharing of risk. The use of a deadband creates an incentive for the utility to control costs because if results fall within the deadband, there is no adjustment to rates, and no sharing is required. Annual reconciliation filings can be designed to provide adequate information and reporting and an explanation of material variances between actual utility costs and forecasts. The long-term nature of an MRP improves transparency into the utility's spending plans, and the annual reconciliation mechanism protects customers by ensuring that rates properly reflect the utility's investments. The same as traditional rate recovery mechanisms, the Commission would continue to determine which costs incurred by the utility are prudent and reasonable.

**14. Should alternative forms of regulation be designed to recover the cost of specific, clearly identified capital projects, and, as appropriate, Operations and Maintenance Costs? Should the Commission require public utilities to provide ongoing reports on the status of planned projects and, when a public utility changes its capital project plans, to propose appropriate changes to its cost recovery mechanisms?**

Alternative regulation should be designed to recover the revenue requirement, which includes the cost of specific investments, planned capital programs and O&M costs. A meaningful alternative regulation proposal would provide the utility the flexibility to deploy capital and make system investments as system needs change over time. A utility's internal financial planning forecast can be used as the basis for setting its rates, such as through an MRP. Finally, annual reporting provides an opportunity for the utility to apprise parties and the Commission of the status of key projects.

**15. What terms, conditions, and procedures should the Commission establish to provide ratepayers with notice of a public utility's alternative forms of regulation plan and provide opportunities for ratepayers to comment and participate in the ratemaking process?**

The Commission already engages in extensive public outreach regarding utility proposals and provides opportunities for public comment. Therefore, the Commission would not need to adopt additional notification procedures regarding an alternative ratemaking proposal. However, any notices provided should clearly state that the utility has made such a proposal.

The Commission should also ensure that there are transparent, informal processes outside of any formal rate case proceeding, such as workshops or technical conferences, which afford interested parties the opportunity to be informed of the alternative ratemaking proposal and to have the opportunity to offer feedback to the utility. Workshops or technical conferences allow the parties to gain a better understanding regarding performance-based regulation, alternative ratemaking, performance incentive mechanisms and similar elements of alternative ratemaking. This effort serves to inform all stakeholders prior to and during the ratemaking proceeding.

Finally, ongoing community engagement by the utility provides an opportunity to inform customers and community leaders. The utility outreach typically includes attending neighborhood association and other community meetings, use of educational collateral and engagement with local community leadership.

**16. Are there ROE and capital structure implications related to alternative forms of regulation?**

<u>Capital Structure and Rate of Return</u>

The capital structure (percent of equity and debt) and authorized ROE should be established at the beginning of the MRP and remain constant over the term of the MRP. Setting the ROE for the entirety of the term allows the utility to plan and alleviates the administrative burden and cost to re-litigate and seek an authorized ROE each year. The cost of debt should also be established at the beginning of the MRP, however, if an annual reconciliation filing is included, the cost of debt should be adjusted annually to reflect the most current cost of financing with any adjustment flowing through the annual reconciliation filing.

Considerations in establishing an ROE

Utility companies are capital-intensive by nature, needing to finance large and long-lived projects with the help of externally generated funds from investors. Since the ratio of revenues generated by a utility is low relative to the level of capital investments it makes, a utility generally does not generate adequate cash flow to fund its capital construction program. In order to meet the obligation to provide safe and reliable service and meet the changing and growing needs of customers and stakeholders, utilities must have access to investor-supplied capital. To attract external funds, a utility must provide a competitive return to investors given the risk of the business and the industry in which the utility operates. To do so, it must compete with other utilities and other firms in the capital markets. In that sense, a reasonable return should be competitive with those available on investments of comparable risk. Investors have many choices and will favor investing in companies that offer competitive and reasonable investment returns over companies that offer less competitive or bottom-of-the range investment returns. As noted during Technical Conference III, a competitive return "[r]ecognizes the level of risk facing the company as compared to alternative investment options" and is viewed in comparison to industry averages.[28]

A utility's ROE is generally established based on a proxy group of peer companies of similar risk and financial characteristics. Many of the utility companies that make up a utility's proxy group may already have various forms of alternative recovery mechanisms. As an example,

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28 RRA Panel 2 Presentation, Slide 18.

the companies in the Pepco ROE proxy group have alternative recovery mechanisms in the following percentages: capital trackers (51%), performance-based regulation (46%), future test years (39%), formula rates (6%) and allowance of Construction Work in Progress in rate base (56%).[29] This means that approving an alternative recovery mechanism for a utility that is compared to a proxy group of companies that already include many alternative recovery mechanisms simply allows the utility to earn an ROE that is more in line with that of its proxy group. Approval of an MRP or other alternative recovery mechanism, therefore, should not result in a lower ROE. If the ROE were to be reduced, it would only move the utility farther away from its peers, making it more difficult to compete for capital at reasonable costs and terms.

Additionally, alternative recovery mechanisms do not necessarily reduce the overall financial risk of the utility such that a reduction in the authorized ROE is warranted. Under an MRP, as an example, some of the new financial risks that are introduced highlight the need to bolster the ROE as compared to a traditional historic test period approach:

- The MRP sets rates for several years into the future, which is an increased risk on the utility to manage actual costs versus forecasts. Any material changes in circumstances or unforeseen extraordinary events during the term of the MRP may not be recovered and present a financial risk to the utility.
- The ROE is generally set for the term of the MRP. Utilities are highly sensitive to interest rates. As interest rates increase, utility valuations decrease, driving up the required utility equity return or ROE. This represents a risk to the utility as the cost of equity to fund new investments may be higher than the level set in the MRP, and the utility would not have the ability to adjust its ROE during the MRP term;

[29] Formal Case No. 1156, PEPCO (G): Hevert Direct Testimony at 51.

- In Technical Conference III, all participants agreed that the utility continues to have the burden of proof and must justify the prudency of its investments regardless of the method used to recover its investments. In that sense, the risk of recovery remains unchanged in an MRP.

As a final point, as part of its credit rating evaluation, rating agencies highlight credit risks associated with the lack of capital tracking mechanisms and lagged cost recovery. Although approval of an alternative recovery mechanism for a utility that lacks capital tracking mechanisms or experiences lagged cost recovery may be viewed as credit positive based on the facts and circumstances, the credit impact may only move the credit risk of the utility closer to that of its peer group and make the utility more comparable to its peers. In other words, the mechanisms support the utility's existing credit profile but does not necessarily enhance it. It should not be assumed that the credit impact reduces the utility's risk relative to comparable companies.

**17. Are there other issues the Commission should consider?**

None at this time.

## B. PANEL 2 COMMENTS

**1. What have been the experiences of alternative forms of regulation, including MRP, PBR, and PIMs, in other jurisdictions?**

Performance based and alternative regulation in various forms is widely applied in the United States as well as internationally. Seventeen states have MRPs[30] and 16 states have PIMs.[31] Moreover, in the United States, several states have many years of experience with both PIMs and

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30 This includes states that have a multiyear rate plan for either natural gas or electric utilities. Grid Modernization Laboratory Consortium, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," sponsored by the U.S. Department of Energy, July 2017.

31 O'Neill Management Consulting, LLC, "Recommendations for Strengthening the Massachusetts Department of Public Utilities' Service Quality Standards," Prepared for the Massachusetts office of the Attorney General, December 2012.

MRPs. For example, New York has used MRPs since the 1970s, when they were adopted to address the need to reduce workload for the New York Commission's staff, and the California Public Utility Commission ("California PUC") has one of the longest history of PBR in North America for retail energy utility services (although its plans are not always called PBR). PBR was initially implemented in California to contain costs and better align utilities' strategies with public policy goals (largely conservation efforts at the time).[32] Similarly, Massachusetts established PIMs more than a decade ago.

These alternative forms of regulation have not been static but, instead, have evolved over time. For example, the California PUC first approved two-year MRPs for Southern California Edison in 1980. The standard plan increased to three years in 1984, and since that time four- and even five-year rate plans have also been approved by the California PUC, though these longer periods are less common. The California PUC has also permitted different forms of attrition relief mechanisms ("ARMs") and energy cost trackers to be incorporated into such rate plans to account for additional revenue requirements between rate cases.[33] Finally, utilities in California have experimented with different rate designs and demand-side management PIMs. Although such PIMS have largely been effective in furthering demand-side management goals, the California PUC has not explored earnings sharing mechanisms and service quality PIMs as heavily as other jurisdictions.

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[32] For additional detail, see Grid Modernization Laboratory Consortium, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," sponsored by the U.S. Department of Energy, July 2017.

[33] Revenue decoupling has also been implemented to mitigate the incentive for utilities to boost retail sales and further power conservation policy goals.

**2. What are the best practices being implemented to assure prudence review is adequately conducted during the reconciliation process so that it is not overburdensome but achieves the purpose?**

Although there are no industry-wide surveys of best practices for the reconciliation process, as a general matter, the reconciliation process should have the following characteristics:

- Limited in scope and focused on resolution of reconciliation-related issues. It should not be used to re-litigate issues that the Commission resolved in the base rate case (*e.g.*, rate design).
- Time limited in order to mitigate impacts of regulatory lag and allow timely reconciliation, which can provide customer and utility benefits.
- Standardized such that filing expectations are clear and sufficient to allow an efficient regulatory process.

**3. Should an alternative form of regulation always require a proposal for base year (historical test year), a bridge year and one or more forecasted test years? What are the pros and cons for different forms and proposals?**

When forecasting continuing expenses, historical data should be provided to allow for the benchmarking of forecasts. A 2013 NRRI report that surveyed state public utility commissions reported that most commissions require or encourage a utility to present historical data with forecasted test years (although not necessarily as part of an MRP).[34]

The forecasting needs for MRPs vary considerably depending on the specific type of plan selected. For example:

- In an MRP that uses a I-X factor, the revenue cap is determined on the basis of growth rates applied to the results of an historical test year.

[34] *See*, Ken Costello NRRI, "Future Test Years: Evidence from State Utility Commissions," Report No. 13-10, October 2013.

- If one uses a Stairstep approach, the revenue requirement is based on forecasted test year results.

As Pepco's presenter indicated, the term "Bridge Year" is not an industry-wide standardized term; however, the term can be used to refer to the period linking the historical and the forecasted periods used in an alternative form of regulation such as an MRP. Similar constructs exist in other jurisdictions, such as Pennsylvania, which includes a fully historical test year, a fully projected test year, and a "future test year," which is the link between the fully historical and fully projected test years.

**4. What are the best practices for reporting requirements regarding forecasted vs. actual values, measures for reconciliation and timelines?**

The Commission, in Order No. 18846 in Formal Case No. 1139, clearly indicated that a reconciliation mechanism is an important feature of any alternative regulation proposal.[35] The Company agrees.

As was apparent from the discussion of this question at the technical conference, there are no industry-wide surveys of reconciliation processes, and no best practices have been developed. As referenced in Question 2, to provide administrative efficiency while also giving the Commission effective oversight of the outcomes and outputs achieved through alternative regulation, it is important that the reconciliation process be:

- Limited in scope and focused on resolution of reconciliation-related issues rather than re-litigating issues that were decided in the general rate case such as rate design.

[35] In that order, the Commission directed that "Pepco needs to provide a mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year." Formal Case No. 1139, Order No. 18846 at ¶594.

- Time limited to mitigate impacts of regulatory lag and allow timely reconciliation so that benefits are timely incorporated into rates.
- Standardized such that filing expectations are clear and sufficient to allow for an orderly and efficient regulatory process.

5. **Based on other states' experiences, which ones have implemented a "successful" alternative ratemaking mechanism which leads to just and reasonable rates while achieving other goals such as grid modernization, Distributed Energy Resource ("DER") development, electrification, renewable expansion, grid reliability, resiliency and innovation, improvements in executing accelerated pipeline replacement programs, reduced natural gas leak rates, meeting natural gas quality of service standards, reductions in gas outages, and improvements in pipeline safety damage ratios?**

Success can be hard to determine, as whether an alternative ratemaking mechanism was implemented "successfully" depends on the needs and goals of the particular jurisdiction. That said, many jurisdictions appear to have successfully implemented MRPs and PIMs. The continued use of alternative ratemaking mechanisms by states over many years along with a continued increase in the number of states moving toward the use of alternative ratemaking demonstrates that alternative ratemaking is meeting the objectives of the states and leads to just and reasonable rates. For example, there are several evolving public policy goals, such reducing GHG and increasing the penetration of electric vehicles, that have been addressed through the adoption of PIMs. PIMs are distinguished from "tracking only" metrics through the use of a financial impact (either penalty or reward). New York has the most PIMs related to evolving public policy goals in place through its Earning Adjustment Mechanisms or EAMs. Hawaii is currently in the process of developing new PIMs, having identified a number of key areas on which to focus its efforts.

However, developing PIMs that reflect public policy goals and that the utility can reasonably impact is an ongoing challenge due to mismatches in the broad policy outcomes and the relatively limited sphere of utility influence. While many jurisdictions and public reports have identified potential areas for PIM development, the actual implementation of PIMs (*i.e.*, reported metrics with financial consequences) is relatively limited.

In May 2016, the New York Public Service Commission issued the NY Reforming the Energy Vision ("REV") Track Two Order, which created a new regulatory model that incentivizes utilities to achieve objectives such as attracting distributed energy resources ("DERs") and reducing GHG. As part of the NY REV proceeding, the New York Commission established EAMs, a form of performance incentive under which utilities can earn a return for achieving NY REV objectives. The New York Commission identified five "opportunity areas" for utilities to develop EAMs and allowed a maximum of 100-basis point reward across the EAMs. EAMs are evaluated by the New York Commission for their effectiveness in the following opportunity areas: system efficiency and peak reduction; energy efficiency; distributed generation interconnection; customer engagement; and GHG reduction. Con Edison's EAM proposal initially included six EAMs that could provide the utility with a reward but not a penalty and two reporting only EAMs.[36]

The Hawaii Public Utilities Commission has identified three areas in which to develop two to six new PIMs: interconnection experience, customer engagement, and DER asset effectiveness.[37] The development of the individual metrics within the three areas is ongoing through a stakeholder process. In addition to the new PIMs, the Hawaii Public Utilities

[36] Since this time, the "Distributed Generation Interconnection" has been removed due to improved performance and statistically unreliable survey data from developers, which underlies a portion of the EAM.

[37] Public Utilities Commission of the State of Hawaii, Decision and Order No. 36326, Docket No. 2018-0088, (May 23, 2019).

Commission proposed developing new shared saving mechanisms and reporting-only metrics (some with goals).

In Rhode Island, an initial settlement negotiated by National Grid and parties included seven public-policy-oriented PIMs; however, an amended settlement maintained only one of the seven. The PIM approved by the Rhode Island Public Utilities Commission ("RI PUC") in the amended settlement was annual MW capacity savings which the RI PUC implemented as a peak reduction program. The RI PUC decided to track additional metrics (which had been PIMs in the original settlement) without financial consequences. The RI PUC left open the potential for National Grid to become eligible for a performance incentive for additional metrics, such as: installed energy storage capacity; avoided $CO_2$ from consumer electric vehicles; light duty government and commercial fleet electrification; awarded low-income and multi-unit EV service equipment ("EVSE") sites; interconnection (time to ATI).[38] The RI PUC is actively engaged in a review of principles to guide the development of PIMs.[39]

### 6. Under alternative forms of regulation, what are the best practices for the true-up or reconciliation process that the Commission should consider?

As was noted under Question 4 above, there are no industry-wide surveys of reconciliation processes, and no "best practices" have been developed. In practice, the reconciliation processes included in MRPs applied throughout the U.S. vary in scope (which includes plan elements such as costs, revenues, earnings) and eligible categories (such as targeted investments, full revenue requirement). Some reconciliations are symmetric with under- and over-estimates "trued-up," but most are not.

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[38] National Grid also has a non-wires alternative program called "System Reliability Procurement."

[39] *See* http://www.ripuc.org/eventsactions/docket/4943page.html"

MRP reconciliations based on earnings are relatively common. As of 2015, fourteen states had electric MRPs and of those, ten had reconciliations, which are typically referred to as earning sharing mechanisms ("ESMs").[40] Most, though not all, ESMs are asymmetric, reconciling only over-earnings. ESMs can vary significantly in structure. Some include a deadband in which no sharing takes place. If earnings fall outside of the deadband established for the ESM, sharing may include several "bands" with varying percentages of sharing between customers and the utility depending on how far outside of the deadband the actual earnings fall (e.g., 50/50, 75/25, 90/10). For example, the ESM for Consolidated Edison has a 50 basis point deadband. The first sharing band is 50 basis points wide and shares overearnings 50% to customers. The second sharing band is 50 basis points wide and shares overearnings 75% with customers. The final sharing band, which is any overearnings beyond the first two bands, is shared 90% with customers.[41]

Although historically the Hawaiian electric companies have had a one-sided ESM in which only over-earnings were shared with customers, the Commission staff in Hawaii recently proposed, and the Hawaii Commission prioritized in its order, the development of an ESM with "upside" and "downside" sharing outside a deadband. The design of an appropriate deadband and sharing bands is now being discussed through a stakeholder process. The Hawaii Commission retained the use of revenue decoupling to true up revenues to an annual revenue target as part of the MRP. The Company's understanding is that the Staff of the Maryland Public Service

[40] Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared by Pacific Economics Group, November 11, 2015 (EEI 2015 Update)

[41] State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016.

Commission is also currently considering a reconciliation process that incorporates an "upside" and "downside" true up mechanism in Case No. 9618.[42]

Other reconciliations within an MRP may target certain types of costs, such as property taxes. For example, the Consolidated Edison MRP includes approximately 20 line items to reconcile, including pension and other post-employment benefits and property taxes.[43] In the case of New York, these costs are typically treated symmetrically (*i.e.*, there are true ups for both under- and over-spending relative to forecasts), and the reconciliation is deferred over the term of the plan.

As Pepco's presenter noted, she is aware of three jurisdictions that have implemented reconciliations related to transmission and distribution capital investments in the context of an MRP. The three jurisdictions that Pepco's presenter discussed include New York (Consolidated Edison),[44] Minnesota (Northern States Power), [45] and New Hampshire (Public Service Company of New Hampshire).[46] These reconciliations are focused on the aggregate levels of plant in service (or similar metrics) rather than individual investments.

**7. Is it a best practice to require updated forecasts over the term of an MRP? If so, what specific updates are needed?**

MRP revenue requirements/price caps are set in the rate case and are not updated during the term of the plan. Although updated forecasts for revenue requirements are typically not

42 *In the Matter of the Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or a Gas Company*, MdPSC Case No. 9618.

43 *Id.*

44 *Id.*

45 State of Minnesota Office of Administrative Hearings, Findings of Fact Conclusions of Law and Recommendations, Docket No. 15-826, March 1, 2017, and Minnesota Public Utilities Commission, Findings of Fact Conclusions and Order, Docket No. 15-826, June 12, 2017.

46 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010

required, MRPs often include one or more mechanisms to allow for "course correction" if initial forecasts differ significantly from actual results. Such mechanisms may include:

- Earning sharing mechanisms that allow the MRP to correct based on the earnings actually achieved as compared to the regulated allowed earnings.
- Reconciliations that adjust for specific types of costs (*e.g.*, property tax or pension) or capital expenditures (or plant in service), although reconciliations for specific investments are generally related to larger projects, such as a new generating facility.
- Accommodations, such as deferred accounting to address extraordinary events, that appropriately allow the utility to absorb (or refund) unanticipated large expenditures in areas that are outside of the utility's control, such as major storm costs or changes in tax laws.
- Off-ramps and reopeners that allow the Commission on its own motion or the parties to request the Commission to review the approved MRP if it is not performing as expected and the problem cannot be resolved through any other mechanism available under the MRP.

**8. How have the credit rating agencies viewed the implementation of alternative forms of regulation for electric and natural gas distribution utilities?**

The credit rating agencies have articulated that the impact of alternative forms of regulation will vary based on the scope and implementation. All else held equal, those regulatory approaches that provide faster and more assured forms of cost recovery are generally considered to be credit positive. Whereas regulatory approaches that create uncertainty in recovery are generally considered by the ratings agencies to be credit negative. Many forms of alternative regulation do not fall neatly into one or the other box but, rather, have elements that could produce credit positive or negative outcomes. For example, as Pepco's presenter noted, language from Moody's rating methodology for regulated electric and gas networks includes multiple areas where alternative regulatory mechanisms could produce credit positive or credit negative outcomes.[47]

The specific details of any alternative regulatory mechanisms have to be carefully assessed as they may include a range of aspects, some of which will be viewed as being credit positive while others will be viewed as having credit negative outcomes. One has to look at the totality of these differing factors.

**9. What have been states' experiences with how alternative forms of regulation, and specifically an MRP, affects the public utility's incentive to improve its cost performance?**

Although examining the impacts that specific regulatory approaches and mechanisms have upon costs and rates is an area of interest to economists and academics, as Pepco's presenter noted, it is a complex analysis. Conducting such a study would require accounting for numerous variables and developing a "but-for" case (*i.e.*, what the world would look like if the regulatory approach had not been applied). None of the Panel 2 participants identified any empirical studies that have been completed concerning the effectiveness of MRPs.

**10. What have been states' experiences with how adopting alternative forms of regulation, and specifically an MRP, affects the public utility's non-cost related performance?**

Although from a conceptual standpoint MRPs, depending on their features, could create incentives for a utility to control its costs in a way that could result in service degradation, Pepco's presenter was not aware of any studies (systematic or otherwise) that have addressed non-cost-related performance in the United States. In order to address this potential issue, MRPs are

[47] Formal Case No. 1156 Technical Conference III Panel 2: Implementation Experiences in Other States Brattle Group Presentation at p14 (October 18, 2019).

frequently paired with PIMs that are designed to incentivize the utility to maintain or even improve upon pre-determined service levels.

**11. Do alternative forms of regulation change the role of the Commission and other stakeholders? If so, what if any additional resources will the Commission need?**

No, the use of an alternative form of regulation, such as MRPs and PIMs, should not fundamentally change the role of the Commission and parties, as these forms of alternative regulation are adjuncts to, rather than a wholesale departure from, cost-of-service regulation. Indeed, as was discussed under Question 3 of the Panel 1 Comments above, in the case of an MRP, the Commission's oversight ability is enhanced because the Commission receives a longer-term view of future capital and O&M investments before the utility makes the investments, increasing transparency as well as the utility's ongoing reporting requirements as part of the MRP. Moreover, one of the benefits often identified for implementing MRPs is to ease the demands on regulatory commission staffs by eliminating the utility's need for back-to-back, annual base rate case filings.

Finally, as was noted in the presentation submitted by Pepco's presenter, staff members from other commissions that relatively recently implemented MRPs indicated that:

> [I]t is not that the alternative regulatory models are driving the need for more staff and differently skilled staff. The major driver is the technological change: cost reductions in new distributed technologies and greater urgency to address climate goals. The alternative regulatory models are more a reaction, rather than the cause, for the new needs.[48]

> [A]t no time have additional Staff been contemplated in response to the needs of alternate regulation. What is possible is that occasionally and within narrowly defined financial limits we may be able to bring in consultants to support additional needs.[49]

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48 *Id.* at p15.

49 *Id.*

### 12. What rules or regulations should the Commission implement if it decides to move forward with alternative forms of regulation?

It is difficult at this juncture to suggest specific rules or regulations that the Commission should implement as this ultimately will depend on the form of alternative regulation that the Commission is seeking to implement. Thus, the suggestions would be different if the Commission elected to implement a formula rate, for example, than if it chose to use an MRP. Moreover, even within a specific alternative form of regulation, there could be significant differences depending on the elements the Commission determined it wished to incorporate. For example, the regulations for an MRP that is based on a utility's projections of future O&M and/or capital expenditures could differ significantly from one in which some or all costs were increased from a base year based on a particular index or a combination of outside measures or factors. Furthermore, it is unclear whether the Commission wishes to only permit one form of alternative regulation or whether it will consider more than one option.

Fortunately, the Commission's organic statute clearly vests it with broad authority to consider and implement alternative forms of regulation. Thus, in the context of electric distribution service, Section 34-1504(d) of the D.C. Code expressly confers on the Commission the authority to "regulate the regulated services of the electric company through alternative forms of regulation." Additionally, the Commission's current rules of practice and procedure vest the Commission with the authority to waive any regulatory requirements that it deems appropriate.[50]

Given that such alternative regulation will be new, at least in the context of energy utilities in the District of Columbia, the Commission should wait to undertake formal changes either to

[50] *See* 15 D.C.M.R. §146.1. The Company is cognizant that the Commission is currently considering changes to its Rules of Practice and Procedure in RM1-2019. Any rules ultimately adopted by the Commission should retain this broad discretionary authority on the part of the Commission to waive any requirements of its rules.

Chapter 1 or to add one or more new chapters to Title 15 of the District of Columbia Municipal Regulations until the Commission and parties have seen the issues that arise in the context of the implementation and operation of an actual alternative regulation framework. The Company's current MRP proposal as well as the MRP that Washington Gas Light Company has indicated it intends to submit next year will allow the Commission and stakeholders the opportunity to gain real world experience in the District regarding alternative regulation before embarking on changes to Title 15 of the District of Columbia Municipal Regulations to address any such alternative regulation.

The Commission adopted a similar approach in connection with the price-cap plans under which Verizon Washington, DC Inc. ("Verizon") has been regulated since 1996.[51] Such alternative regulation was expressly permitted by the terms of the *Telecommunications Competition Act of 1996*,[52] which provided that Verizon could "petition the Public Service Commission for an alternative form of regulation, or for forbearance of regulation." Despite the passage of more than twenty years, the Commission has not found it necessary to alter its existing regulations to accommodate this alternative form of regulation of Verizon.

[51] The first price cap plan was adopted in November 1996 when the Commission approved a Non-Unanimous Full Settlement Agreement in Formal Case No. 814, Phase IV. At that time, the telephone company was known as Bell Atlantic – Washington, D.C., Inc. *See* Formal Case No. 814, Phase IV, Order No. 10877 (November 12, 1996).

[52] D.C. Law 11-154, effective September 9, 1996, codified at D.C. Code §§ 34-2001 *et seq.*

## III. CONCLUSION

Pepco appreciates the opportunity to complete the record with its Comments.

Respectfully submitted,

POTOMAC ELECTRIC POWER COMPANY

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November 1, 2019

# ATTACHMENTS


# Framework for Evaluating Alternative Ratemaking Proposals

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## Formal Case No. 1156 Technical Conference

October 17, 2019

# Background

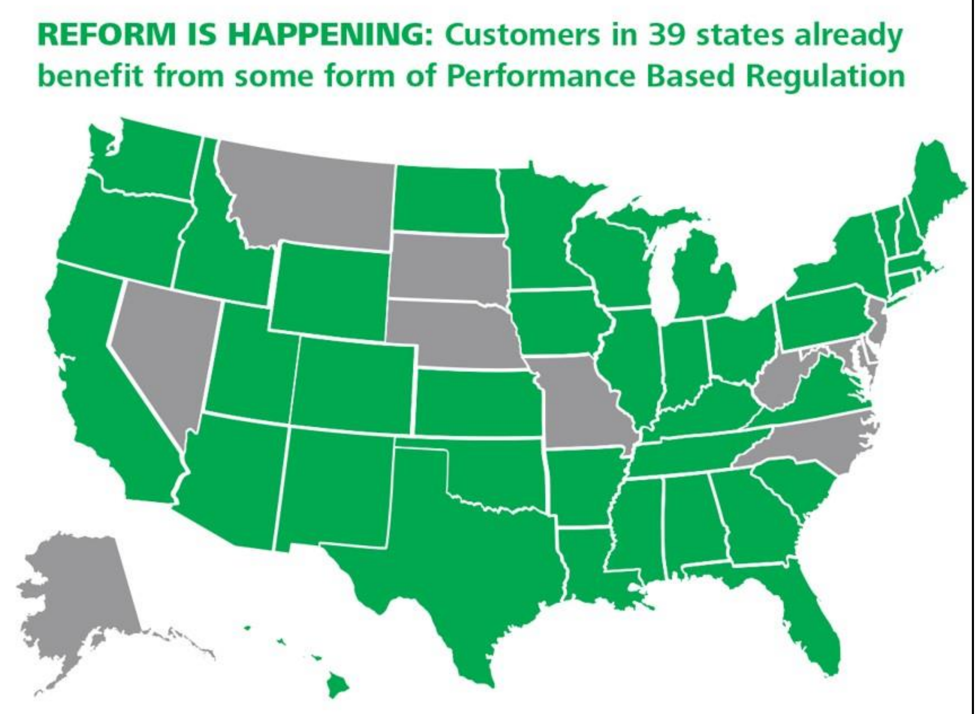
- In FC 1103 & 1139, the Commission expressed interest in alternatives to the traditional ratemaking approach to reduce the frequency of rate cases
- FC 1156, Order No. 20204:

  *The purpose of this technical conference will involve identifying alternative ratemaking approaches, including PIMs, that further the Commission's MEDSIS goals and the District's energy related objectives, such as electrification, renewable development, pipeline replacement*

- Purpose of the technical conference: (Public Notice, Sept. 18)
  - Explore potential risks and benefits of the alternative forms of regulation
  - Explore additional designs stakeholders want to consider (including performance based rates, earnings sharing mechanisms, or other ways to unlock benefits for customers)

# Alternative Ratemaking in the United States

- Alternative ratemaking is well-established in the United States
- Several jurisdictions across the US employ Multiyear Rate Plans (MRPs), PIMs, fully forecasted test years, formula rates, and capital trackers
- In Order No. 18846, the Commission stated that Pepco may file either an MRP or fully-forecasted test year in a future rate application




Source: Edison Electric Institute Testimony before the Maryland Public Service Commission, PC51, April 2019

# Customer Benefits of Multiyear Rate Plans

- Improves the alignment of utility performance with the District's sustainability goals
- Increases visibility into utility financial planning process
- Increases utility accountability and provides incentive for managing resources and administrative costs
- Reduces the frequency of rate cases
- Provides customer bill certainty
- Encourages innovation
- Improves overall financial health of the utility which lowers borrowing costs and rates

Pepco chose to propose an MRP because an MRP provides the best opportunity to realize all of the benefits described above

Q2



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# Evidence to Support Alternative Forms of Regulation

- The Commission should primarily consider the existing laws regarding its selection of an appropriate type of alternative regulation mechanism.
- DC Code § 34-1504 (d) sets the standard for the Commission's consideration of alternative regulation:
  - Protects Customers
  - Ensures the quality, availability, and reliability of regulated electric services; and
  - Is in the interest of the public, including shareholders of the electric company.

Q1 & Q4



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# Other Evidence to Support Alternative Forms of Regulation

The Commission should consider other factors (in addition to existing laws) as it evaluates an alternative form of regulation proposal:

- Just and reasonable rates
- Customer protection
- Financial health of the utility
- District energy and other policy goals
- Commission policy goals
- Lower administrative and regulatory costs/burden



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# Commission Oversight to Assure Prudent/Efficient Costs

- Commission maintains oversight of the utility, regardless of the specific form of alternative regulation proposed
  - Utility always retains the burden of proof
  - Information provided in advance and ongoing reporting improves transparency and enhances oversight
- Alternative forms of regulation provide the Commission, stakeholders, and customers with a longer-term view of future capital and operation and maintenance investments before the utility makes those investments
- Commission and stakeholders have enhanced visibility into and opportunity to review and discuss planned spend prior to the Company making system investments
- Ongoing utility reporting allows Commission and parties to review actual results with projections and utility to describe any material variances

# Specific Performance Outcomes and Key Goals

- The implementation of several key energy goals and initiatives are currently underway in the District
  - District policy goals set forth in the Clean Energy Omnibus Act
    - Maximize renewable sources of energy, including the amount of solar energy deployed in the District
    - Energy efficiency, particularly focused on low- and medium-income residents
    - Reduction of greenhouse gases
    - Transportation electrification
  - Commission policy goals set forth in PowerPath DC
    - "Ensuring that our energy delivery system remains safe, reliable, and affordable while also becoming more sustainable, interactive, and secure"
    - Actual policy goals adopted by the Commission (*e.g.,* TE working group and PowerPath DC proposed order) can inform future potential PIMs
- Several workstreams are underway at the Commission that will identify specific performance outcomes and targets to achieve the District and Commission policy goals
  - The product of these workstreams will help delineate the role of the utility
- Specific performance outcomes and targets to achieve the clean energy goals and PowerPath DC should be developed after the Commission implements the goals

# Current Metrics and Development of New Metrics

- Current metrics were developed independently
  - Electric Quality of Service Standards (EQSS)
  - Merger commitments
  - Separate rulemakings and Commission orders
- PIMs can be used to drive policy and incentivize utility performance
- Ideally, PIMs should have the following characteristics:
  - PIMs must be measurable
  - Utility should be able to reasonably impact the outcome of the PIM
  - PIMs outside of the utility's control should be tracking-only PIMs
- PIMs for future consideration may reflect the following topics:
  - Reliability metrics
  - Supplier diversity and local business engagement
  - Energy efficiency
  - Pepco's reduction of its greenhouse gas emission

Q5-9



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# Cost of Service, Rate Design, and Jurisdictional Allocation

- Any discrete change to rate design can be done either in the context of a traditional test period or an MRP
- The rate design methodology for the entirety of the MRP should be determined prior to the start of the MRP
- Jurisdictional allocations should change year-to-year, based on a forecasted allocation
- Class cost of service should not change during the MRP term and should be based on traditional test period or historical data
- Alternative regulation does not reduce the need for a bill stabilization adjustment

Q10

# Utility Financial Forecasting Methodology

- The Commission should approve an alternative form of regulation proposal that preserves the utility's flexibility to deploy capital and make system investments, while still holding the utility accountable to manage its overall budget
- Any alternative regulation proposal that is based on forecasted costs should include:
  - Description of financial forecasting
  - List of initiatives
  - Financial planning assumptions
  - Transparency into financial planning and cost forecasting
  - Historical cost data
- Annual reporting with explanations of material cost variances will provide visibility and transparency
- Commission and parties will have opportunity to review financial forecasting methodology as part of MRP proceeding

Q11

## Reconciliation Process

- Annual reconciliation mechanisms can ensure appropriate sharing of risk between utility and customers
- Annual reconciliation filings can be designed to provide adequate information and reporting and explanation of material variances between actual utility costs and forecasts
- Long-term nature of the MRP structure incentivizes utilities to make prudent system investments
- A reconciliation mechanism will protect customers by ensuring that rates properly reflect the investments made in the system

# Alternative Regulation & Specific Investments

- Alternative forms of regulation should be designed to recover the revenue requirement, which includes the cost of specific investments, planned capital programs, and operations and maintenance costs
- An alternative form of regulation should provide the utility the flexibility to deploy capital and make system investments as system needs change over time
- Utility's internal financial planning forecast can be used as the basis for setting its rates
- Annual reporting provides an opportunity for the utility to apprise stakeholders and Commission of the status of pivotal projects

Q14



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# Opportunities for the Public/Customers to Comment

- Commission continues to engage in extensive public outreach regarding utility proposals and opportunities for public comment
- Pre-filing stakeholder workshops can provide an opportunity to inform stakeholders and for the utility to receive stakeholder input
- Ongoing community engagement can provide an opportunity to inform customers and community leaders by attendance at neighborhood association meetings, through educational collateral, and through other engagement with local community leadership

Q15

# ROE & Capital Structure Implications

- A competitive ROE benefits customers by providing the opportunity to attract funds on reasonable terms to make system investments
- "Base" ROE should be set at the beginning of the rate effective term for the entirety of the rate effective term
- Administratively burdensome and costly to re-litigate authorized ROE each year
- Capital structure and cost of debt can be adjusted on an annual basis as part of a reconciliation mechanism

Q16



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# Panel 2: Implementation Experiences of Other States

**PRESENTED TO**

FC 1156 Technical Conference

**PRESENTED BY**

Pearl Donohoo-Vallett
William Zarakas

October 18, 2019

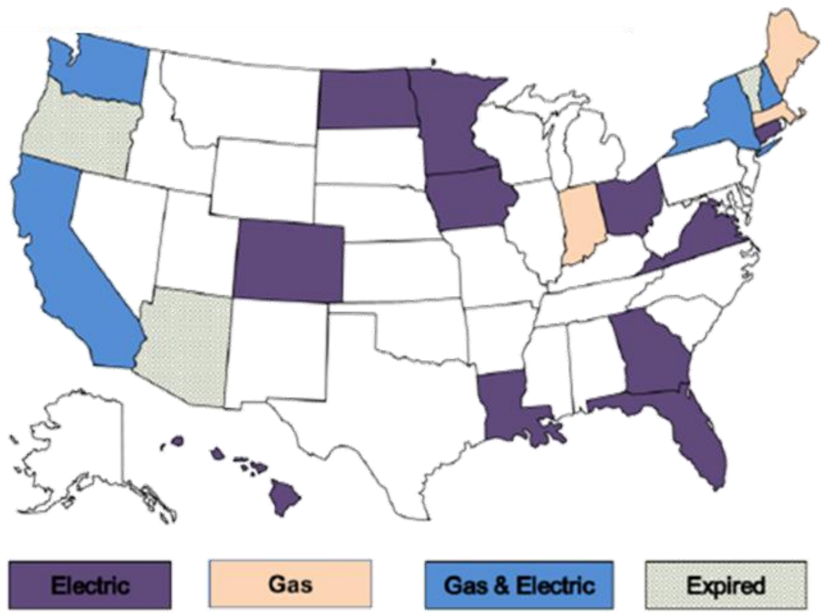
THE Brattle GROUP

# Question 1: Overview

*What have been the experiences of alternative forms of regulation, including MRP, PBR, and PIMs, in other jurisdictions?*

- Performance based & alternative regulation in various forms is widely applied in the U.S. and internationally
  - 17 states have MRPs
  - 16 states have PIMs
- In the United States, several states have accrued years of experience with PIMs and MRPs. For example:
  - New York's use of MRPs traces to the 1970s and the need to reduce workload for its commission staff
  - Massachusetts PIMs were established in 2009 and revised in 2014

**MRPs in the U.S. by Utility Type**




Grid Modernization Laboratory Consortium, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, sponsored by the U.S. Department of Energy, July 2017.

# Question 1: The California Experience

## Background

The California PUC has the longest history of PBR in North America for retail energy utility services (although its plans are not always called PBR). PBR was initially implemented in California to contain costs and utilities' strategies with public policy goals (largely conservation efforts at the time).

- The PUC first approved two-year MRPs for Southern California Edison in 1980. The standard lag increased to 3 years in 1984.
- Four- and five-year rate plans have also been approved (although they are less common).

ARMs, energy cost trackers, and planned "stepped rate" increases are allowed to account for additional revenue requirements between rate cases. Revenue decoupling has been implemented to mitigate the incentive for utilities to boost retail sails (in accordance with power conservation policy goals. Utilities in California have also experimented with different rate designs and demand-side management PIMs.

## Pros

- History of sustained PBR use and success
- PIMs has been largely effective in regards to demand-side management

Source:
Grid Modernization Laboratory Consortium, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," July 2017, https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

## Cons

- Evidence of fraud in some of the PIMs tracking (e.g., customer service surveys)
- Earnings sharing mechanisms and service quality PIMs have not been explored as heavily

# Question 5: Overview

*Based on other states' experiences, which ones have implemented a "successful" alternative ratemaking mechanism which leads to just and reasonable rates while achieving other goals such as grid modernization, Distributed Energy Resource ("DER") development, electrification, renewable expansion, grid reliability, resiliency and innovation, improvements in executing accelerated pipeline replacement programs, reduced natural gas leak rates, meeting natural gas quality of service standards, reductions in gas outages, and improvements in pipeline safety damage ratios?*

- Many evolving public policy goals (reduction in greenhouse gases, increasing penetration of electric vehicles, etc.) have been addressed through adoption of performance incentive mechanisms (PIMs)
  - New York has the most programs *in place* through the "Earning Adjustment Mechanisms"
  - Hawai'i is in the process of developing new PIMs having identified key areas
- Developing PIMs that reflect policy goals <u>and</u> that the utility can reasonably effect is an ongoing challenge

# Question 5: Summary of ConEd EAMs (1)

**The NY REV Track Two Order (issued May 2016) creates a new regulatory model that incentivizes utilities to achieve REV objectives**

- REV seeks to attract distributed energy resources (DERs) to meet system needs, at lower cost than conventional solutions

**Earning Adjustment Mechanisms (EAMs) are incremental performance incentives under which utilities can earn a return for achieving REV objectives**

- Each utility proposes its performance areas, targets, metrics, and incentive levels
- Con Edison proposal was approved in spring 2017, other NY utilities are in the process of filing and seeking EAMs approval
- EAMs are evaluated for their effectiveness with chances for revision

EAM opportunity areas:

| |
|---|
| System Efficiency and Peak Reduction |
| Energy Efficiency |
| DG Interconnection |
| Customer Engagement |
| Greenhouse Gas Reduction |

# Question 5: Summary of ConEd EAMs (2)

| Metric | Penalty or Reward? | Outcome or Programmatic? | Max RY1 Incentive ($) | Measured Target Metric |
|---|---|---|---|---|
| Distributed Energy Resource Utilization | Reward | Outcome | $2,720,000 | Overall MWh measured by MW of installation |
| Energy Intensity (MWh sales/customer) | Reward | Outcome | $2,710,000 | Weather normalized energy sales divided by 12-month average # customers[1] (separate for Residential and Commercial) |
| AMI Customer Awareness | Reward | Outcome | $500,000 | Customer survey responses on AMI awareness post-AMI deployment |
| Energy Efficiency | Reward | Programmatic | $9,220,000 | GWh reductions from the System Peak Reduction Program, EE Program, and Energy Efficiency Transition Implementation Plan (ETIP)[3] |
| Peak Reduction | Reward | Programmatic | $3,460,000 | Peak Reduction MW[3] (includes EV program) |
| Distributed Generation Interconnection | Reward (y1 – reporting only) | Outcome | RY1: None *Removed as Reward Eligible* | Compliance with Standard Interconnection Requirement timeliness and independent third party customer satisfaction surveys |
| Customer Load Factor | Reporting Only | Outcome | N/A | Customer average summer demand divided by customer peak demand[2] |
| Greenhouse Gas Reductions | Reporting Only | Outcome | N/A | $CO_2$e reductions determined through pre-defined formulae for a targeted subset of technologies |

Sources and Notes:
State of New York Public Service Commission, Joint Proposal, Case 16-E-0060, September 19, 2016.
State of New York Public Service Commission, Con Edison 2017 Energy Efficiency Earnings Adjustment Mechanism Achievement Report, March 30, 2018.
1. The number of customers used for the commercial metric is the number of private employees in the 6 counties served by ConEd.
2. The Customer Load Factor metric is still in development.
3. Each year’s performance judged independently of previous years’ performance

# Question 5: Hawai'i Proposed Areas

**The Hawai'i Commission identified three areas to develop 2-6 new PIMs: Interconnection Experience, Customer Engagement, and DER Asset Effectiveness**

- The Commission also proposed developing new shared saving mechanisms and reporting-only metrics (some with goals)

| Goal | Regulatory Outcome | | PIM | SSM | Scorecard | Reported Metric |
|---|---|---|---|---|---|---|
| Enhance Customer Experience | Traditional | Affordability | | | | X |
| | | Reliability | X | | | |
| | Emergent | Interconnection Experience | X | | X | |
| | | Customer Engagement | X | | X | |
| Improve Utility Performance | Traditional | Cost Control | | X | X | |
| | Emergent | DER Asset Effectiveness | X | | | |
| | | Grid Investment Efficiency | | X | | |
| Advance Societal Outcomes | Traditional | Capital Formation | | | | X |
| | | Customer Equity | | | | X |
| | Emergent | GHG Reductions | | | X | |
| | | Electrification of Transport | | | | X |
| | | Resilience | | | | X |

# Question 5: National Grid RI (1)

On August 24, 2018, the Rhode Island Public Utilities Commission approved an amended settlement in the National Grid rate case with only one of the seven PIMs in the original settlement:

- Annual MW Capacity Savings will be implemented as a peak reduction program
- The Commission has decided at this time to track additional metrics (PIMs in original settlement) without financial consequences and National Grid may become eligible for a performance incentive for additional metrics, such as:
  - Installed Energy Storage Capacity
  - Avoided CO2 from Consumer EVs
  - Light Duty Government and Commercial Fleet Electrification
  - Awarded Low-Income and Multi-Unit EV Service Equipment (EVSE) sites
  - Interconnection (Time to ISA)

National Grid also has a non-wires alternative program called "System Reliability Procurement"

# Question 5: National Grid RI (2)

**The following list of emerging PIMs was discussed in National Grid's most recent rate case**

- Only the Annual MW Capacity Savings PIM is to be implemented based on amended settlement
- Initial maximum first-year reward of $1.4 million revised to $362,000 (2019) and rising to $944,000 (2021) in the amended settlement[1]

| Metric | Penalty or Reward? | Outcome or Programmatic? | Max Incentive ($) | Measured Target Metric |
|---|---|---|---|---|
| System Efficiency: Annual MW Capacity Savings | Reward | Outcome | $362,085 (2019) | MW of annual peak capacity savings from resources including: demand response, distributed PV in excess of forecast levels, and incremental storage |
| DER: Installed Energy Storage Capacity | Reporting only | Outcome | Removed in amend. settlement | Incremental installed energy storage capacity |
| DER: $CO_2$ Electric Vehicles | RY1: Reporting only[2]<br>RY2: Potential reward | Outcome | Removed in amend. settlement | Incremental avoided tons of $CO_2$ resulting from EV initiative |
| DER: Light Duty Government and Commercial Fleet Electrification | RY1: Reporting only<br>RY2: Potential reward | Outcome | Removed in amend. settlement | Incremental increase of government and commercial light-duty EVs |
| Power Sector Transformation: Activated Apartment Building and Disadvantaged Community EVSE[3] | Reporting only | Outcome | Removed in amend. settlement | In-service date of make-ready work and charging stations |
| Power Sector Transformation: DG Interconnection – Time to ISA[4] | Reporting only | Outcome | Removed in amend. settlement | No. of business days from executed ISA to distribution system modifications |

Sources and Notes: National Grid, Amended Settlement Agreement, Rhode Island PUC, Docket Nos. 4470/4780, April 16,2018. National Grid, Settlement Agreement, Rhode Island PUC, Docket Nos. 4470/4780, June 6,2018.

1. Initial settlement included rewards for all categories listed above and a $CO_2$ metric for electric heat, which is removed in the amended settlement.
2. Rate Year 1 (RY1) means September 1, 2018 through August 31, 2019. Rate Year 2 (RY2) means September 1, 2019 through August 31, 2020.
3. EVSE = Electric Vehicle Service Equipment.
4. ISA = Interconnection Service Agreement.

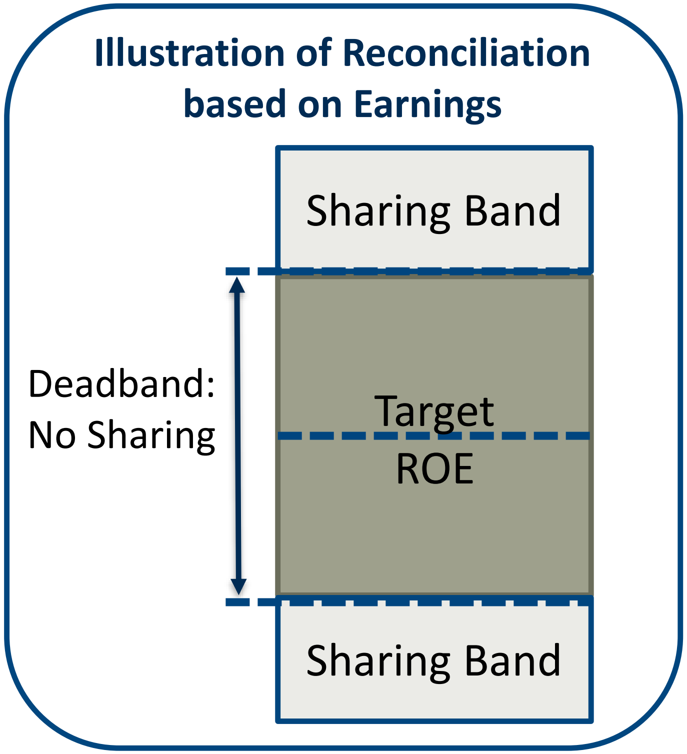
# Question 6: Overview

*Under alternative forms of regulation, what are the best practices for the true-up or reconciliation process that the Commission should consider?*

- While analysts are not clear as to what constitutes the "best" practice, we are able to point to the predominant practices in place
- There are multiple forms of reconciliations used under alternative regulatory mechanisms that vary in scope (e.g., costs, revenues, earnings) and eligible categories (e.g., targeted investments, full revenue requirement)
  - Some are symmetric with under- and over-estimates "trued-up" to actuals
  - Most are not symmetric
- Multi-year rate plans include a variety of reconciliation types
  - Return on equity reconciliations
  - Specific cost reconciliations (e.g., property taxes)
  - Capital investment reconciliations (e.g., plant balances)

# Question 6: Overview Cont'd

- MRP reconciliations based on earnings are relatively common
  - 14 states had electric MRPs (as of 2015)
  - 10 of the 14 states had reconciliations, typically referred to as earning sharing mechanisms ("ESMs")
  - Most ESMs are asymmetric, reconciling only over-earnings
- Earning sharing mechanisms vary in structure
  - Some include a deadband in which no sharing takes place
  - Outside the deadband, sharing may include several "bands" with varying percentages of sharing between customers and the utility (e.g., 50/50, 75/25, 90/10)




Source: Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared by Pacific Economics Group, November 11, 2015 (EEI 2015 Update).

# Question 6: HECO Proposed Structure

**Commission staff in Hawai'i proposed, and the Commission prioritized in its Order, the development of an earning sharing mechanism (ROE reconciliation) with "upside" and "downside" sharing outside a deadband**

- The design of the deadband and sharing bands is being discussed through a stakeholder process
- Historically, the Hawai'ian electric companies have had a one-sided earning sharing mechanism, sharing only over-earnings

## Revenue Adjustment Mechanisms in Staff's February 2019 PBR Proposal

| Revenue Adjustment Mechanisms | |
|---|---|
| **Multi-Year Rate Plan (MRP) and Indexed Revenue Cap** | **5-Year Control Period** with **Externally-Indexed Revenue Cap** allowing interim adjustments pursuant to a revenue cap index formula:<br>**RevCapIndex** = (**Inflation**) - (**X-Factor**) + (**Z-Factor**) - **Consumer Dividend**[20] |
| **Revenue Decoupling** | Continue to utilize **revenue decoupling** (i.e., the Revenue Balancing Account ["RBA"]), to true up revenues to an annual revenue target, which ensures the utility receives the target revenue, regardless of increases or decreases in energy sales |
| **Earnings Sharing Mechanism (ESM)** | Apply a modified **ESM** that provides both "upside" and "downside" sharing of earnings between the utility and customers when earnings fall outside a Commission-approved range |

# Question 8: Overview

*How have the credit rating agencies viewed the implementation of alternative forms of regulation for electric and natural gas distribution utilities?*

- There is no one-size-fits all answer to how alternative regulatory practices impact utilities
  - Regulatory approaches that provide faster and more assured forms of recovery are generally credit positive
  - Regulatory approaches that create uncertainty in recovery are generally credit negative
- Implementation of "credit positive" alternative regulatory mechanisms may act as a counterweight to an otherwise "credit negative" environment

**Excerpts from Moody's Downgrade of HECO**

"The rating downgrade reflects the strained relationship with its regulators and interveners as it strives to replace its fossil-based generation with renewable sources. We expect there to be continued friction with regulators and interveners because HECO is expected to implement, through its utility operations, ambitious public policy goals.."

"Tempering our concerns is HECO's robust suite of regulatory cost recovery mechanisms and a supportive legislative framework to facilitate the transformation. Hawaii's cost recovery mechanisms provide for, among other things, revenue decoupling, a forward test year and automatic recognition of baseline capital expenditures…"

Source: Moody's Investor Service, "Moody's downgrades Hawaiian Electric Company from Baa2 to Baa1, "August 3, 2016 https://www.moodys.com/research/Moodys-downgrades-Hawaiian-Electric-Company-to-Baa2-from-Baa1-Outlook--PR_352972

# Question 8: Overview Cont'd

**Moody's rating methodology for regulated electric and gas networks includes multiple areas where alternative regulatory mechanisms could produce credit positive or negative outcomes**

EXHIBIT 2

**Regulated Electric and Gas Networks**

| Broad Grid Factors | Factor Weighting | Sub-Factors | Sub-Factor Weighting |
|---|---|---|---|
| Regulatory Environment and Asset Ownership Model | 40% | Stability and Predictability of Regulatory Regime | 15% |
| | | Asset Ownership Model | 5% |
| | | Cost and Investment Recovery (Ability and Timeliness) | 15% |
| | | Revenue Risk | 5% |

**Excerpts from Guidelines**

- Aa :Unanticipated expenditure quickly reflected in allowed revenue with low, if any, efficiency investment
- Ba: "…Unanticipated expenditure slow to be reflected in allowed revenue or may be subject to stringent efficiency assessment/low sharing factor"

| Aaa | Aa | A | Baa | Ba | B | Caa |
|---|---|---|---|---|---|---|
| No exposure to volume risk. Collected revenues based on capacity charges. | Very low exposure to volume risk. Collected revenues based on volume charges with stable volumes expected. Revenue cap mechanism with timely recovery in place. | Limited exposure to volume risk. Collected revenues based on volume charges with some volatility in volumes expected. Revenue cap mechanism in place; OR Hybrid price/revenue cap with low volatility in volumes. | Moderate exposure to volume risk. Hybrid price/revenue cap with moderate volatility in volumes; OR Some reliance on connection revenues. | Material exposure to volume risk: price cap with significant volatility in volumes; OR Material reliance on connection revenues. | High exposure to volume risk: price cap with substantial volatility in volumes; OR Very high reliance on connection revenues. | Very high exposure to volume risk: price cap with high concentration of volumes to one particular customer or sector; OR Revenues mainly driven by connections. |

# Question 11: Overview

*Do alternative forms of regulation change the role of the Commission and other stakeholders? If so, what if any additional resources will the Commission need?*

- Two alternative forms of regulation considered by the Commission (MRPs and PIMs) do not fundamentally change the role of the Commission and stakeholders
- These forms of alternative regulation are adjuncts to rather than a departure from cost-of-service regulation
  - Based on an informal survey, two Commission staff members from states with relatively recent implementation of multi-year rate plans stated:

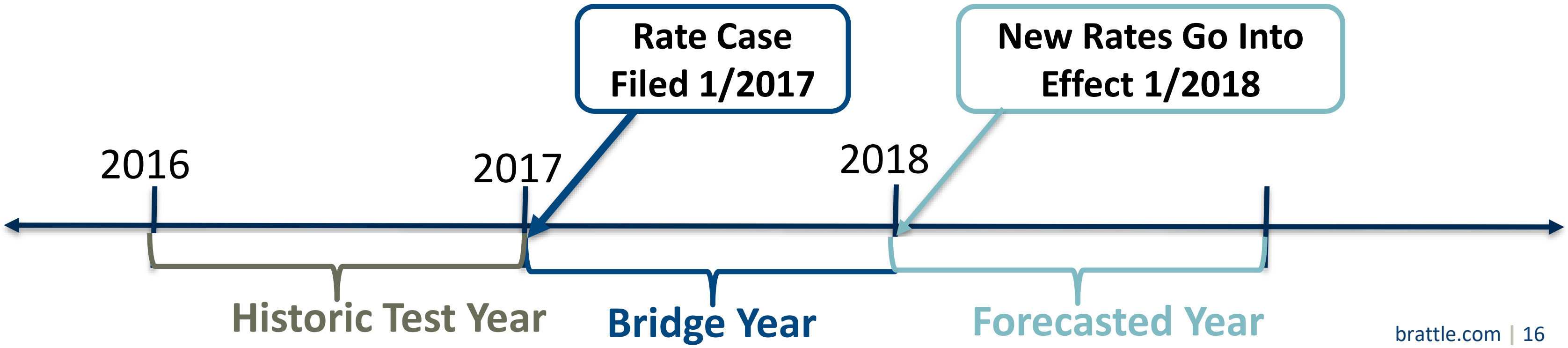
    *"…it is not that the alternative regulatory models are driving the need for more staff and differently skilled staff. The major driver is the technological change: cost reductions in new distributed technologies and greater urgency to address climate goals. The alternative regulatory models are more a reaction, rather than the cause for the new needs."* and

    *"…at no time have additional Staff been contemplated in response to the needs of alternate regulation. What is possible is that occasionally and within narrowly defined financial limits we may be able to bring in consultants to support additional needs."*
  - Easing demands on staff has been cited by multiple public utility commissions as the driver to adopt multi-year rate plans

# Question 3: Overview

*Should an alternative form of regulation always require a proposal for base year (historical test year), a bridge year and one or more forecasted test years? What are the pros and cons for different forms and proposals?*

- When forecasting continuing expenses, historical data should be provided to allow benchmarking of forecasts
- The term “Bridge Year” itself is not an industry-wide standardized term
  - In Pennsylvania, for example, a historical test year, future test year (the year of the rate case also called the “rate year”), and a fully projected future test year are used in some rate cases
  - “Bridge years” can be used to explain the transition between historical and forecasted periods



# Question 3: Forecasting

*Should an alternative form of regulation always require a proposal for base year (historical test year), a bridge year and one or more forecasted test years? What are the pros and cons for different forms and proposals?*

- The forecasting needs for *MRPs* varies by plan type
  - I-X: Revenue cap with growth rates applied to a historical test year
  - Stairstep: Revenues requirement based on forecasted test years
- A 2013 NRRI Report that surveyed state public utility commissions reported that most commissions require or encourage a utility to present historical data with forecasted test years (not necessarily associated with an MRP)
  - Most require 1 year of historical data
  - Illinois requires 3-years of historical data comparing forecasts and actuals
  - Kentucky requires the most historical data (5-years)

# Questions 2 &4:

*What are the best practices being implemented to assure prudence review is adequately conducted during the reconciliation process so that it is not over burdensome but achieves the purpose?*
*What are the best practices for reporting requirements regarding forecasted vs. actual values, measures for reconciliation and timelines?*

- There are no industry-wide surveys of reconciliation processes and best practices
- Our general guidance on regulatory processes is that the reconciliation process should be:
  - Limited in scope and focused on resolution of reconciliation-related issues, not re-litigate issues settled in the general rate case (e.g., rate design)
  - Time limited to mitigate impacts of regulatory lag and allow timely reconciliation, which can provide either customer or utility benefits (e.g. processes limited to 120 days before rate changes go in effect on an interim basis)
  - Standardized such that filing expectations are clear and sufficient to allow an efficient regulatory process

# Question 7: Overview

*Is it a best practice to require updated forecasts over the term of a MRP? If so, what specific updates are needed?*

- MRP revenue requirements/price caps are set in the rate case and then not updated during the term of the plan
- Typically, MRPs include one or more mechanisms to allow for “course-correction” if initial forecasts differ significantly from actual
  - Earning sharing mechanisms allow the policy to correct based on earnings
  - Reconciliations adjust for differences in targeted (e.g., a specific investment) or broad (e.g., net plant) investments
  - Accommodations for extraordinary events (e.g., deferred accounting) allow for the utility to absorb (or refund) unanticipated large expenditures (e.g., major storms or changes in law)
  - Off-ramps allow parties to review and potentially refile if the MRP is not performing as expected

# Question 9: Overview

*What has been states' experiences with how alternative forms of regulation, and specifically an MRP, affects the public utility's incentive to improve its cost performance?*

- Examining the impacts that specific regulatory approaches and mechanisms have upon costs and rates is an area of interest to economists and academics.
- However, conducting such studies involve accounting for numerous variables and developing a "but-for" case (i.e., what the world would look like if the regulatory approach had not been applied). We are not aware of any empirical studies that have been completed concerning the effectiveness of multi-year rate plans.

# Question 10: Overview

*What has been states' experiences with how adopting alternative forms of regulation, and specifically an MRP, affects the public utility's non-cost related performance?*

- Conceptually, multi-year rate plans can create incentives to control costs, which could result in service degradation
- We are not aware of any studies (systematic or otherwise) that have addressed non-cost related performance in the United States
- MRPs are frequently paired with PIMs to incentivize utilities to maintain or improve upon pre-determined service levels

# Question 12:

*What rules or regulations should the Commission implement if it decides to move forward with alternative forms of regulation?*

*This question requires detailed knowledge of the existing rules and regulations in the District, which is beyond our realm of expertise.*

PRESENTED BY

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At Brattle, her work for utilities, merchant transmission developers, and regulators focuses on distribution utility business models, performance and alternative ratemaking, distributed energy resources, clean energy policy, and transmission planning.  To these issues, Dr. Donohoo-Vallett brings her breadth of experience across transmission planning, system operation, renewable portfolio standards, distributed energy resources, and alternative ratemaking mechanisms to help clients identify, understand and address emerging utility challenges. In addition to her work in the energy field, Dr. Donohoo-Vallett is active within the firm’s pro bono practice.

Dr. Donohoo-Vallett earned her PhD in Technology, Management, and Policy as well as SM in Technology and Public Policy from the Massachusetts Institute of Technology.  She earned her B.S. in Mechanical Engineering from the Franklin W. Olin College of Engineering.

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# Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates

## RESPONSE TO PC51 REQUEST FOR COMMENTS

**PREPARED FOR**

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March 29, 2019

THE Brattle GROUP

# Notice

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*Note that this version of the report has been updated to address formatting inconsistencies.*

# Table of Contents

# I. Introduction

The Brattle Group was asked by the Joint Utilities of Maryland[1] to apply our ongoing research of regulatory issues and processes in order to answer questions posed by the Maryland Public Service Commission ("Commission") with respect to the Commission's issuance of its Notice of Technical Conference: *Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*.

In its Notice of Technical Conference on Alternative Forms of Rate Regulation, the Commission asked six primary questions concerning:

1. The manner in which those state regulatory commissions determined which alternative rate plans were acceptable;
2. The implementation period to transition from one form of regulatory rate making principles to the alternative rate plan;
3. Any restrictions placed by other state regulatory commissions on the use of alternative rate plans, including whether a utility can switch between alternative rate plans in subsequent cases;
4. The frequency by which the utility may file for rate increases under an alternative rate plan;
5. How reconciliations and refunds may be made when the utility is using a forecasted test year or other forecasted methodology; and
6. The impacts on the ratepayers resulting from the use of the alternative rate plans.

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[1] The Joint Utilities are Baltimore Gas and Electric Company, Delmarva Power & Light Company and Potomac Electric Power Company.

In addition to these six questions, the Commission posed a seventh request for information related to whether state commissions with alternative rate plans required additional staff resources or staff with different skills than previously utilized.

This report focuses on three forms of alternative rate plans (or alternative regulatory mechanisms)[2]: future test years ("FTY"), formula rates ("FR"), and multi-year rate plans ("MRPs"). **Future (or forward) test years** seek to minimize imbalances in revenue recovery by setting rates based on best projections, rather than history. **Formula rates** are regulatory mechanisms that allows for periodic adjustment of rates based on forms of "true-ups." The use of formula rates improves alignment of revenue recovery to utility costs by allowing rates to more closely track changes in utility operations. **Multi-year rate plans** are designed to improve overall utility performance in controlling costs. Under the MRPs, rate cases occur less frequently (typically three or so years in the U.S., but as many as eight under the U.K.'s Revenue = Incentives + Innovation + Outputs, or RIIO plan).

The questions raised by the Commission are appropriate to ask as it is considering the impact of enhancement to its current regulatory regime, and as it considers joining the other states that have adopted alternative regulatory plans. Most of the questions raised are answerable based on the record established in state regulatory proceedings. Two questions, however, are less directly discernable. First, the manner in which state regulatory commissions determine that the benefits of adopting an alternative regulatory mechanism is typically not clearly spelled out in state commission orders and decisions. Second, retrospectively determining the impacts on ratepayers involves complex empirical analysis which has not been undertaken by most (or possibly any) state regulators. Nonetheless, we answered these more difficult questions as best possible based on regulatory records and interviews with staff.

The Brattle Group has undertaken a variety of surveys and studies concerning the scope and motivations underlying the adoption of alternative regulatory mechanisms, which we used to

[2] We use the alternative rate plan and alternative regulatory mechanism terminology interchangeably in this report.

answer the Commission's questions. We also took a "deep dive" approach by selecting ten utilities across different jurisdictions for review. These ten jurisdictions were selected to include a mix of states that have relatively recently implemented an alternative regulatory mechanism as well as jurisdictions with commissions typically considered to be leaders in their field.[3] Within each jurisdiction, we selected a single utility to illustrate how the alternative regulatory mechanism was selected and implemented (see Table 1). While most of these jurisdictions employ multiple alternative regulatory mechanisms (typically a future test year in conjunction with either formula rate or MRP), we have focused on the mechanisms shown in Table 1.

**Table 1: Jurisdictions and Utilities Reviewed**

| State | Utility | Utility Short Name | Alternative Rate Plan Type |
|---|---|---|---|
| New Mexico | Public Service of New Mexico | PSNM | FTY |
| Arkansas | Entergy Arkansas | Entergy | FR |
| Illinois | Commonwealth Edison | ComEd | FR |
| Louisiana | Southwestern Electric Power Company | SWEPCo | FR |
| Florida | Florida Power and Light | FPL | MRP |
| Hawai'i | Hawai'ian Electric Company | HECO | MRP |
| New Hampshire | Public Service Company of New Hampshire | PSNH | MRP |
| New York | Consolidated Edison | ConEd | MRP |
| North Dakota | Nothern States Power | NSP | MRP |
| Washington | Puget Sound Energy | PSE | MRP |

Section II of this report focuses on the initial implementation of alternative rate plans and commission staffing requirements for alternative rate plans (Questions 1 and 7). Section III reviews the structural and implementation details of each utility's alternative rate plan (Questions 2 through 6).

3 Several jurisdictions have long-running alternative rate plans, such as Alabama Power's use of formula rates, which was initiated in 1982. See "Case Study of Alabama Rate Stabilization and Equalization Mechanism", Edison Electric Institute, June 2011.

# II. Commission Processes to Enable Alternative Rate Plans

Regulatory approval of an alternative regulatory mechanism is based on the commission's perspective on the relative risks and benefits of the mechanism or plan, combined with legal and/or regulatory considerations. While described as "alternative," the regulatory mechanisms considered here have recently become mainstream, with a majority of states allowing the use of multi-year rate plan, forward test year, or formula rate, as shown in Table 2.[4] This section discusses the processes through which alternative regulatory mechanisms have been approved, and staffing requirements deemed necessary in order to effectively implement such plans.

**Table 2: Survey of States with Alternative Regulatory Mechanisms for Electric Utilities (*) (includes Washington, D.C.)**

| Mechanism | | Number of States |
|---|---|---|
| Multi-Year Rate Plans | [1] | 20 |
| Formula Rates | [2] | 11 |
| Forward Test Years | [3] | 25 |

Sources and Notes:

(*) Count for formula rates includes states that have also allowed formula rates for gas utilities.

[1] Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute).

[2] Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute); Arkansas Public Service Commission, "Formula Rate Plan Rider," Docket No. 16-052-U, Order No. 8, Approved May 18, 2017. Includes 5 states (Georgia, Oklahoma, South Carolina, Tennessee, and Texas) that have formula rates only for gas utilities.

[3] Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute). S&P Global Market Intelligence Regulatory Research Associates, "Arkansas Regulatory Review," November 4, 2016. Indiana Code Title 8, Utilities and Transportation § 8-1-2-42.7.

[4] Counting the usage of alternative regulatory mechanisms is not as straightforward as it may sound. States are frequently served by multiple utilities, each of which may be regulated under a different mix of mechanisms. Furthermore, state regulators may not always refer to similar mechanisms by the same names, which means that some judgement needs to be applied to draw comparisons across jurisdictions. For example, California and New York both set rates for a three-year rate case cycle, which we consider to be an MRP / incentive regulation approach. However, regulators there refer to it as a three-year general rate case (GRC) cycle. Also, regulators in Oklahoma refer to certain true-up based rate plans (applied to gas LDCs) as performance rate plans; we categorize them as formula rates.

## A. Alternative Regulatory Mechanisms

***Question 1: the manner in which those state regulatory commissions determined which alternative rate plans were acceptable;***

Overall, the application of alternative rate plans on a state-by-state or utility-by-utility basis reflects a combination of the commission's view on the operating environment facing the utility, potential risks and rewards, and both regulatory and legal requirements. However, the scope of a state regulatory commission's authority to implement such plans may be constrained by statute or regulatory precedent. Thus, a commission's decision whether or not to implement an alternative regulatory mechanism may require that state law and/or regulatory code be modified.

State regulatory commissions can readily modify regulatory code when they find potential merit in an alternative regulatory mechanism, if the constraint lies within existing regulatory code. On the other hand, legislation may be required when existing law is explicit on such matters or when statutes specify the options that may be considered by state regulators. Our review indicates that state commissions have typically enabled the use of future test years without legislative input. However, there are examples (such as New Mexico), where modification to regulation and implementation of a future test year required passage of legislation.[5]

In our survey of ten jurisdictions (listed in Table 3), two of the three states with formula rates (Arkansas and Illinois) required passage of enabling legislation. In contrast, as shown in Table 3, none of the states in which regulators approved MRPs required additional legislation, although this is almost certainly not universally the case.[6]

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5 Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 4.

6 In implementing an MRP, the New Hampshire Public Utilities Commission did not specifically reference a legislative precedent, but cited both prior commission precedent and a judicial case related to attrition relief. State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 31.

**Table 3: Enabling Body (Commission or Legislative) of Alternative Regulatory Mechanisms**

| State | Utility Short Name | Alternative Rate Plan Type | Method of Approval |
|---|---|---|---|
| New Mexico | PSNM | FTY | Legislative |
| Arkansas | Entergy | FR | Legislative |
| Illinois | ComEd | FR | Legislative |
| Louisiana | SWEPCo | FR | Commission |
| Florida | FPL | MRP | Commission |
| Hawai'i | HECO | MRP | Commission |
| New Hampshire | PSNH | MRP | Commission, Judicial |
| New York | ConEd | MRP | Commission |
| North Dakota | NSP | MRP | Commission |
| Washington | PSE | MRP | Commission |

From a process perspective, our review indicates that utilities are typically the initiators of regulatory modification; state regulatory commissions typically respond to a request from a utility when approving a specific alternative regulatory mechanism. For example, the District of Columbia Commission's order allowing Pepco DC to file for alternative regulatory mechanisms explicitly included the two mechanisms first proposed by the utility.[7] There have also been stakeholder processes initiated by commissions to investigate alternative regulatory mechanisms, for example the ongoing performance based regulation process in Hawai'i, to thoroughly vet different approaches and incorporate input from all stakeholders. However, these processes are relatively uncommon in our experience due to their prohibitive implementation cost.

Commissions generally will examine whether the alternative rate plan will result in a just and reasonable rate considering a number of factors involved in setting utility rates. Broadly speaking, the process typically involves consideration of various stakeholder perspectives and filing of testimony to discover plan details, potential impacts on the ratepayers and the utility business. Customer costs, utility financial integrity, utility performance and administrative burden of the plan may all be relevant concerns to consider. To the extent that there are jurisdictional policy

[7] Public Service Commission of the District of Columbia, Order No. 18846, Formal Case No. 1139, July 25, 2017, pp. 184-185, 187.

goals (i.e. commitment to grid modernization, increased DER penetration or clean energy targets), they are also taken into account in assessing how the proposed regulatory mechanism helps achieve these goals. The end goal is to agree on an alternative mechanism that will be enabling for the utilities as they pursue investments to meet the needs of an evolving grid, while balancing customer rate impacts and ensuring service quality is maintained.

Excerpts from the settlements approving alternative rate mechanisms for utilities in our survey provide some color around the nature of commissions' considerations when determining their acceptability:

> "The Stipulation and Settlement appears to provide FPL's customers with a degree of stability and predictability with respect to their electricity rates while allowing FPL to maintain the financial strength to make investments necessary to provide customers with safe and reliable power.[…] In addition, we recognize that the Stipulation and Settlement reflects the agreement of a broad range of interests[.]"[8]

> "Moreover, it provides for a series of rate increases intended, among other things, to ensure that the erosion of earnings attributable to attrition will not compel the Company to seek another rate increase in a short time. The settlement agreement offers this protection without unduly burdening customers and without removing all risk from the Company and its shareholders to operate an efficient business. Further, the term of the agreement is long enough to allow the rate changes to be meaningful, without being so long as to lock-in customers or the Company to a losing strategy for an unreasonable period. It also provides some protection for both customers and the Company from over- or under-earning."[9]

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8 Florida Public Service Commission, Order No. PSC-05-0902-AS-EI, Docket Nos. 050045-EI and 050188-EI, September 14, 2005, p. 6.

9 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 41.

As discussed later, and at length in similar reports,[10] alternative regulatory mechanisms are not monolithic. The components of the mechanisms can be structured in a variety of ways. Similarly, a regulatory plan applied to a given utility reflects its unique circumstances as well as jurisdiction specific policy considerations. In practice, this means that a plan may include one or more alternative regulatory mechanisms (e.g. future test year in a multi-year rate plan with an earnings sharing mechanism) in combination with an overall rate of return methodology.

## B. Commission Staffing Requirements

***Question 7: The Commission also is interested in whether other states, in implementing alternative rate plans, required additional staff resources or staff with different skills that previously utilized prior to implementing.***

The three alternative regulatory mechanisms considered here (future test years, formula rates, and MRPs) are all extensions of traditional rate making rather than a fundamental shift in regulatory approach. As a result, the core skills required by commission staff to implement alternative regulatory mechanisms are skills already associated with traditional regulatory plans. In our survey, we did not find staffing concerns cited in relation to the evaluation or implementation of alternative rate plans by commission staff testimony or in final orders for any of the utilities. While possible that these concerns were expressed in a different forum, the lack of commentary appears to indicate that staffing and resources have not been primary concerns for the commissions.

It is true that when commissions transition from the traditional model to an alternative regulatory mechanism, staff may need additional training. For instance, when transitioning from historical to future test years, staff will likely need additional training to gain skills in evaluating cost projections. NRRI's 2013 survey of commissions with regard to their use of future test years found that:[11]

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[10] See for example: Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute).

[11] Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 11.

> "Some commissions reported that they had to acquire new staff expertise. Almost all commissions replied that a FTY took little if any time away from addressing other rate case topics. Only one respondent mentioned that given the limited time for rate cases and the complexity of evaluating forecasts, parties may have insufficient time to assess a utility's forecasts."

In our survey, multiple commissions cited existing staffing concerns as a motivation to enact an alternative rate plan. When a utility's operating environment is changing rapidly (*e.g.*, changes in load, increases in costs, etc.), a historic test year can be out-of-date before the rate case settles, and the utility will have to refile rate cases frequently to update the test year. Frequent rate case filings pose a burden to commission staff, as illustrated by the Washington commission's order regarding PSE's multi-year rate plan:[12]

> "An important policy objective underlying our decision is to relieve all stakeholders and the Commission from the burdens of almost continuous general rate case proceedings that have characterized our utility regulation during recent periods."

Plans that span multiple years, such as MRPs and formula rates, remove the need for full annual rate case filings and, in some cases, implement a mandatory stay-out. Some commissions, such as California, Hawai'i, and New York, have adopted general rate case cycles rather than implementing alternative rate plans on a utility-by-utility basis. That is, they have determined that all utilities will be on a similar, multi-year rate case cycle. The filing dates for utilities are staggered to spread the burden of work on the commission. Future test years mitigate the need for frequent filings as the costs included in the test year are more representative of the utility's operating environment. However, a future test year is a short-term fix, to the extent that the utility's operating environment will continue to change, as the future test year only takes into account a single year in the evolution.

12 Washington Utilities and Transportation Commission, Order 07, Docket Nos. UE-121697 and UG-121705 (consolidated) and Docket Nos. UE-130137 and UG-130138 (consolidated), June 25, 2013, p. 8.

Alternative rate plans that involve annual reconciliations (*e.g.* formula rates) do require filings that require commission staff review. However, these filings are intended to be formulaic, and typically involve pre-determined filing requirements (and formats) and are somewhat limited in scope and timing. For example, ComEd recently completed its eighth filing under a formula rate mechanism. The ROE is determined formulaically (580 basis point premium above the 12-month average U.S. Treasury bond yield) and the cost of capital is then updated to reflect the utility's actual capital structure. The commission does continue to have the authority to investigate the prudence and reasonableness of utility investments, but the overall process is less time-intensive than when all parameters are up for potential challenge. ComEd's recent rate case lasted 6 months from the initial filing in April 2018 to the final order in December 2018.[13]

We have also informally surveyed several staff members from three of the ten states/utilities reviewed in our report. One staff member stated that "*it is not that the alternative regulatory models are driving the need for more staff and differently skilled staff. The major driver is the technological change: cost reductions in new distributed technologies and greater urgency to address climate goals. The alternative regulatory models are more a reaction, rather than the cause for the new needs.*" Another staff member indicated that "*at no time have additional Staff been contemplated in response to the needs of alternate regulation. What is possible is that occasionally and within narrowly defined financial limits we may be able to bring in consultants to support additional needs.*"

# III. Alternative Regulatory Mechanisms in Action

To answer specific questions related to the implementation of alternative regulatory mechanisms, we focused on ten individual utility plans. When possible, we selected the electric utility with the

13 S&P Global Market Intelligence, "RRA Regulatory Focus: Commonwealth Edison," January 4, 2019.

earliest use of the alternative regulatory mechanism in order to capture information on the transition to its use.

## A. Transition to Alternative Regulatory Mechanisms

***Question 2: the implementation period to transition from one form of regulatory rate making principles to the alternative rate plan;***

The transition period to an alternative regulatory mechanism depends to some extent on the origin of the proceeding and enabling body. For the utilities in our survey, the regulatory processes to approve alternative rate plans were either comparable in length to or slightly longer than the process under a traditional regulatory mechanism (see Table 4).[14] However, for those cases where legislative action was required, the legal amendment process typically precedes a filing under the new regulatory mechanism and makes the timelines more uncertain, as discussed in more detail below.

There are a few exceptions with shorter or longer regulatory process timelines: on the extremes are 1) Puget Sound Energy (PSE) in WA, which filed its MRP under an expedited rate case framework approved in the prior rate case filing,[15] and 2) Southwestern Electric Power Company (SWEPCO) in LA, for which the process was drawn out by a series of motions to delay.[16]

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14 The Edison Electric Institute reports a 10-month average regulatory lag (defined as the time between a rate case filing and decision) since industry restructuring. Edison Electric Institute, "Rate Review Summary: Q2 2018 Regulatory & Financial Update."

15 S&P Global Market Intelligence, "Puget Sound Energy, Inc.: WA: D-UE-130137 | Rate Case Profile."

16 See Louisiana Public Service Commission, Docket U-23327 Subdocket A (documents): http://lpscstar.louisiana.gov/star/portal/lpsc/PSC/DocketDetails.aspx?DocketId=363b9e78-800a-4dfc-94de-839f05db879f.

**Table 4: Regulatory Process Timelines for Alternative Rate Plans**

| State | Utility Short Name | Alternative Rate Plan | Initial Filing | Final Order | Duration (Months) |
|---|---|---|---|---|---|
| New Mexico | PSNM | FTY | 08/2015 | 09/2016 | 13 |
| Arkansas | Entergy | FR | 04/2015 | 02/2016 | 10 |
| Illinois | ComEd | FR | 11/2011 | 05/2012 | 7 |
| Louisiana | SWEPCo | FR | 01/2003 | 04/2008 | 64 |
| Florida | FPL | MRP | 03/2005 | 09/2005 | 6 |
| Hawai'i | HECO | MRP | 07/2010 | 06/2012 | 23 |
| New Hampshire | PSNH | MRP | 06/2009 | 06/2010 | 12 |
| New York | ConEd | MRP | 05/1991 | 04/1992 | 12 |
| North Dakota | NSP | MRP | 12/2012 | 02/2014 | 15 |
| Washington | PSE | MRP | 02/2013 | 06/2013 | 5 |

Notes: These timelines refer to each utility's initial alternative rate plan filing.

In cases where legislative action is required to enable the alternative regulatory mechanism, the legal amendment process can add uncertainty to the overall timeline. For example, when ComEd first sought to implement a formula rate plan in conjunction with its infrastructure investment commitments under the 2011 Energy Infrastructure Modernization Act (Senate Bill 1652), the filing was preceded by then-Governor Pat Quinn's veto of SB 1652, and a subsequent override by the Illinois Legislature. The revised bill (HB 3036) that was eventually signed by the Governor (in December 2011) had not yet been approved when ComEd filed its formula rate plan under a concurrent regulatory docket.[17] However, the regulatory approval timeline itself was fairly concise: ComEd's initial filing was submitted in November 2011 and the proceeding was decided on in May 2012. Similarly, in Arkansas, Entergy filed its rate case in April 2015, the same year as changes to the Arkansas Code. The order approving Entergy's formula rate plan was finalized in February 2016 about 10 months after the initial filing. Entergy's first annual filing for a true-up was in July 2016.[18]

17 S&P Global Market Intelligence, "Electric Capital Investment Legislation Signed by Illinois Governor," January 4, 2012.

18 S&P Global Market Intelligence, "Entergy Arkansas, LLC: AR: D-15-015-U | Rate Case Profile."

The New Mexico legislature allowed the use of future test years in 2009. The first rate case including a future test year (for Southwestern Electric Power Co.) was filed in 2012 and settled 15 months later.[19] Although the time period between New Mexico enabling future test years and the settling of its first case is extended, the time period is not representative of all, or even most, states. For example, Michigan's legislature enabled the use of future test years in 2017,[20] and Consumers Energy filed a rate case in March 2017, using a projected test year, that was finalized in March 2018.[21]

The use of a pilot program, or other transition mechanism, are commonly used in utility regulation to limit the scope of a new approach (e.g., limiting to a subset of utility expenditures) or scale of the approach (e.g., limiting the time span of the program) when the costs or benefits of an approach are uncertain. Other transition mechanisms can include phase-ins, whereby the scope of a program is gradually increased, or the use of additional reporting (monitoring), which can help the commission to understand how a mechanism may work in practice prior to adding financial incentives. Reporting-only mechanisms have been used, for example, when introducing emerging performance incentive mechanisms with novel scopes and metrics.

Based on our review of jurisdictions, pilot programs are not commonly used for the alternative rate plans considered. Specifically, pilot programs were not used for any of the utility rate plans surveyed. We are familiar with one instance of a formula rate plan being first implemented on a trial basis, which was then continued on a non-trial basis.[22] Because many alternative rate plans are limited in term, they already take on the structure of a time-limited pilot program. This time

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19 S&P Global Market Intelligence, "New Mexico Public Regulation Commission."

20 S&P Global Market Intelligence, "Michigan Public Service Commission."

21 S&P Global Market Intelligence, "RRA – Rate Case Final Report Consumers Energy Co.", August 9, 2018.

22 Corporation Commission of the State of Oklahoma, Order No. 499253, Cause No. PUD 200400187, November 24, 2004, p. 8.

limitation provides a defined point for re-evaluation of the plan's performance. This was the view adopted by the New Hampshire commission in its approval of PSNH's MRP:[23]

> "We also note that though this is not designated as a "pilot" or similar program, see id. at 15, the limited term of the settlement agreement effectively renders it a short term program. We find this limitation important because a great deal may change during the term of the settlement agreement and it may be advisable to revise or eliminate items such as this in the future."

Commissions may institute additional reporting requirements during a transition to improve confidence in a new regulatory plan, notably those that include the use of projections in determining the revenue requirement. Commissions with projected test years (or other forward looking approaches such as MRPs) frequently request both historical and future test year operational information in the utility filing.[24] For example, Wisconsin requires utilities to file historical sales, O&M expenses, rate base, and working capital balances.[25] This approach, of requesting both the traditional and forward-looking approaches, can also be used to compare regulatory plans.

## B. Transitions between Regulatory Plans

***Question 3: any restrictions placed by other state regulatory commissions on the use of alternative rate plans, including whether a utility can switch between alternative rate plans in subsequent rate cases;***

Commissions do not typically require utilities to maintain an alternative rate plan in future rate cases, and utilities can and do switch between traditional and alternative rate plans. The approach

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23 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 32.

24 Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 9.

25 *Ibid.*, p. 32.

for regulating a utility may change over time. For example, Entergy New Orleans was regulated under formula rates from 2004-2006 and then from 2010-2012.[26] Likewise, PSNH was regulated under an MRP from 2010-2015 and then returned to traditional rate making as the utility transitioned through the sale of generation assets.[27] These transitions between regulatory approaches may reflect changes to the underlying operating environment that prompted the use of the alternative regulatory plan or reflect other exogenous factors. We are unaware of any jurisdictions in which utilities have switched between multi-year rate plans and formula rates. Excluding utilities that are on a general rate case cycle (*i.e.*, HECO and ConEd), the utilities in our survey were not required to maintain formula rates or MRPs beyond the current term.[28]

The ability of a utility to transition between traditional rate making and an alternative rate plan (typically formula rates or multi-year rate plans), is bounded by stay-out requirements and mandatory refiling dates. Stay-out requirements prevent utilities from refiling for a change in base rates (or regulatory plan) for a certain number of years, typically 3-5 years. Stay-out requirements frequently include clauses to account for unanticipated events with significant financial impact and may allow a utility to refile if earnings are below a certain threshold. For example, PSNH's plan allowed the utility to refile if its allowed ROE dropped below 7%,[29] and NSP's plan included the ability to file for increased rates if an exogenous event results in a revenue requirement impact of at least $1.5 million.[30] As shown in Table 5, all of the MRPs in the survey included mandatory

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26 Mark Newton Lowry, Matthew Makos, Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update", Edison Electric Institute, November 11, 2015, Table 8.

27 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010.

State of New Hampshire Public Utilities Commission, Order 25,920, Docket No. DE 14-238, July 1, 2016.

28 None of the orders included such a requirement. The Louisiana PUC explicitly confirmed that it was up to the utility to re-propose a formula rate in its next general rate case.

29 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 9.

30 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, p. 33-34.

stay-outs. At the end of the plan's term, the utility may be required to file a general rate case.[31] This mandatory refiling allows for typical rate case reviews as well as modifications to alternative rate plans.

**Table 5: Rate Case Filing Restrictions and Requirements for Surveyed Utilities**

| State | Utility Short Name | Alternative Rate Plan Type | Mandatory Stayout? | Mandatory Refiling Date? | Required Continuance of Alternative |
|---|---|---|---|---|---|
| New Mexico | PSNM | FTY | **X*** | – | – |
| Arkansas | Entergy | FR | – | **X** | – |
| Illinois | ComEd | FR | – | **X** | – |
| Louisiana | SWEPCo | FR | – | **X** | – |
| Florida | FPL | MRP | **X*** | – | – |
| Hawai'i | HECO | MRP | **X*** | **X** | **X** |
| New Hampshire | PSNH | MRP | **X*** | **X** | – |
| New York | ConEd | MRP | **X** | – | **X** |
| North Dakota | NSP | MRP | **X** | – | – |
| Washington | PSE | MRP | **X** | **X** | – |

Notes: (*) indicates that there are off-ramp provisions that allow the utility to refile for a general rate case under certain conditions. PSNM has a mandatory stay-out that may not be related to the future test year.

## C. Frequency of Rate Changes and Reconciliation of Forecasts

***Question 4: the frequency by which the utility may file for rate increases under an alternative rate plan;***

***Question 5: how reconciliations and refunds may be made when the utility is using a forecasted test year or other forecasted methodology;***

Reconciliations between utility forecasted and actual costs, revenues, or a combination thereof are common across a variety of regulatory mechanisms. Cost trackers are a regulatory mechanism used in 45 states that can provide for a reconciliation between forecasted expenditures and actuals. Likewise, decoupling can provide a true-up between forecasted and actual revenues, typically on a per-customer basis. These mechanisms, including riders and decoupling, can, and frequently are,

31 If a utility is not required to file, rates are typically frozen at the level of the last year of the term.

used in combination with future test years, formula rates, and multi-rate year plans.[32] We have not included these reconciliations in our discussions of alternative regulatory mechanisms.

Utilities regulated under formula rates and MRPs typically have the potential for annual rate changes based upon pre-approved changes to the revenue requirement, reconciliations related to ROEs, and reconciliations between forecasted and actual expenditures. Customers may experience rate decreases, rate increases, or no change in rates on a year-to-year basis depending on the design of the plan and the utility's performance. In our survey of utility rate plans, all nine with a formula rate or MRP included the potential for annual rate changes,[33] these potentials for rate changes and reconciliations are summarized in Table 6.

**Table 6: Reconciliations in Surveyed Alternative Rate Plans**

| State | Utility Short Name | Alternative Rate Plan Type | ROE Reconciliation | | Reconciliation (Non-ROE) | |
|---|---|---|---|---|---|---|
| | | | Over Earning | Under Earning | CapEx | OpEx |
| New Mexico | PSNM | FTY | X* | – | – | – |
| Arkansas | Entergy | FR | X | X | – | – |
| Illinois | ComEd | FR | X | X | – | – |
| Louisiana | SWEPCo | FR | X | X | – | – |
| Florida | FPL | MRP | X | –* | X | – |
| Hawai'i | HECO | MRP | X | – | – | – |
| New Hampshire | PSNH | MRP | X | – | X | – |
| New York | ConEd | MRP | X | – | X | X |
| North Dakota | NSP | MRP | X | – | – | – |
| Washington | PSE | MRP | X | – | – | – |

Notes: (*) PSNM has an earning sharing mechanism as part of a rider that predates the future test year. If the ROE for FP&L falls below 9.6%; FP&L may file with the Commission for an increase in rates.

Under formula rates, base rates are typically adjusted based on ROE reconciliations. Backward true-ups compare the utility's earned ROE for the historic year compared to an allowable range (deadband) for the earned ROE. If the utility's ROE is outside the deadband, then rates are either

32 Because decoupling and formula rates accomplish similar goals, the two are not used in combination.

33 At least one MRP, the NSP MRP included a year with a mandatory base rate increase moratorium. State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, p. 5.

increased or decreased to adjust the utility rates to allow the utility to make-up the difference between the target ROE and the earned ROE. The target ROE may be the allowed ROE (e.g., ComEd and Arkansas), the edge of the deadband, or some percentage of the difference between the allowed and earned ROE (e.g., Louisiana). As the true-up is on the utility, both capital and operating expenditures are included. In addition, formula rates also include a forward adjustment. The forward adjustment compares a projected ROE to the allowed ROE range. If the projected ROE falls outside the range (outside the deadband) then rates are adjusted on a prospective basis to bring projected ROE back to the target ROE.

Multi-year rate plans typically have reconciliations more limited in scope and typically focused on capital expenditures, to the extent that reconciliations are included at all. Of the six MRPs included in our survey, three include some type of CapEx reconciliation and only one includes OpEx reconciliations. CapEx reconciliations can be made on the basis of a single investment (e.g., generation plant), investment type (e.g., grid modernization), or across all investments (e.g., distribution system plant). The CapEx reconciliation for FPL focuses on one plant and an allowance for investment in solar generation. The CapEx reconciliations for ConEd and PSNH were based on distribution plant balances. ConEd has multiple OpEx reconciliations including those for property taxes and non-officer variable pay.[34] In addition to the CapEx and Opex reconciliations, MRPs frequently include earning sharing mechanisms in which earnings above earned ROEs (and a deadband) are returned to customers. Each of the MRPs in our survey include an earning sharing mechanism; more broadly 10 of 17 MRPs included earning sharing mechanisms in a 2015 study.[35]

In our survey of MRPs, ConEd has the most reconciliations, with more than fifteen reconciliations across CapEx and OpEx including: property taxes, contractor costs, pensions and other post-employment benefits, environmental remediation, long term debt costs, and a portion of

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34 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 35, 42.

35 Mark Newton Lowry, Matthew Makos, Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update", Edison Electric Institute, November 11, 2015, Table 7.

managerial pay. For the majority of the aforementioned categories, the credits or surcharges resulting from the reconciliation are deferred over the term of the plan and revenue requirement impacts addressed in future rate proceedings.[36] For CapEx, the commission considers net plant balance. If ConEd under invests based on net plant balances on average across the three years, the revenue requirement will be deferred for ratepayers.[37]

Future test years may be used with other regulatory mechanisms that include reconciliations (including MRPs, formula rates, and decoupling), which makes identifying reconciliations related to the use of a future test year in isolation difficult. In the 2013 NRRI survey of future test years, 7 of the 14 utilities indicated that no reconciliations were used.[38] The remaining utilities identified reconciliations resulting from decoupling, ROE reconciliations (related to their existing formula rate plans), reconciliations resulting from MRPs, and rider/tracker reconciliations.[39]

Mechanically, annual adjustments made during the term of the alternative regulatory mechanisms are frequently made through riders. For example, in Louisiana and Arkansas, changes to rates resulting from the ROE true-ups are made exclusively through riders. Likewise under Public Service of Colorado's MRP, sharing of over-earnings would flow through to customers through a rider.[40] By contrast, ConEd delays most reconciliations to the next rate case.[41]

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[36] State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 35.

[37] State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, pp. 28-29.

[38] Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 51-52.

[39] New York stated that in a one-year litigated case, additional expense categories can be subject to true-up including pension, other post-employment benefits, environmental costs, storm costs, etc.

[40] Colorado Public Utilities Commission, Advice No. 1672, Docket 14AL-0660E.

[41] State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, pp. 28-29, 35-50.

## D. Impact on Ratepayers

The impact on ratepayers from the implementation of one or more alternative regulatory mechanisms is difficult to discern, mainly because changes in rates are driven by underlying costs and could have happened under any regulatory approach. Determining whether an increase in rates was caused by the adoption of an alternative rate mechanism requires the development of a counterfactual ("but for") case, i.e., what would have happened to rates if the alternative regulatory mechanism had not been adopted. For example, in Illinois, Commonwealth Edison (ComEd) was required to undertake a grid modernization initiative that involved substantial capital expenditures. It is inaccurate to conclude that the utility incurred grid modernization expenditures because of the formula rate plan; ComEd would have most likely proceeded with the capital program (as it was recognized as a priority for policymakers), and the related costs would have made their way into rates. To our knowledge, empirical studies that estimate correlation between alternative rate plans and an increase or decrease in customer rates, other factors held constant, have not been conducted.[42] However, regulators provided their own assessments of the merits and benefits of alternative regulatory mechanisms at the conclusion of the plan's term. State regulators opted to continue with the alternative regulatory mechanisms in seven of the ten cases that are included in our survey, suggesting that they found the subject plans to be consumer beneficial.

Under traditional regulation, the result of increasing underlying investment can be rate shock, as those new investments are incorporated into rate base. One feature of multi-year rate plans and formula rates is that investments can be integrated into the revenue requirement over time, or rate increases can be spread over the plan period. The gradual nature of rate increases can mitigate the rate shock that would have occurred under traditional regulation.

[42] Even a largely academic study that addresses the impact of regulatory regime on prices (Tooraj Jamasb and Michael Pollitt, "Incentive Regulation of Electricity Distribution Networks: Lessons of Experience from Britain," June 19, 2007) does not fully provide a "but for" case.

# IV. Appendix – Case Studies

## A. Entergy (Arkansas)

| Entergy (Arkansas) – FR | |
|---|---|
| **Term** | 2016 – 2020, inclusive (Docket: 15-015-U; Order No. 18) |
| **Approval** | 2015 legislation (the Formula Rate Review Act) |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Includes an annual filing for ROE reconciliation. Rates are adjusted through the formula rates rider included in the Entergy tariff and are limited to a change of 4% each year.[43] |
| **Mandatory Stay-Out?** | N/A |
| **Mandatory Refiling?** | Entergy must file for a request to extend the formula rate plan beyond 2020. Formula rate terms are limited to five years by the enacting legislation;[44] not required to be under the same plan type. |
| **Reconciliation between Actual and Forecasts** | ROE reconciliation: includes a forward looking adjustment and a backward-looking true-up mechanism; the return on equity is subject to a +/- 50 bps deadband (termed Target Return Rate). Outside the deadband, the ROE is adjusted to reach the allowed ROE subject to the 4% cap on change in revenues on a customer class basis.[45] |

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43 Arkansas Public Service Commission, Order No. 19, Docket No. 15-015-U, March 21, 2016, Rate Schedule No. 44, Formula Rate Plan Rider, 44.5.4.

44 AR Code § 23-4-1208 (2015).

45 Arkansas Public Service Commission, Order No. 19, Docket No. 15-015-U, March 21, 2016, Rate Schedule No. 44, Formula Rate Plan Rider, 44.5.2.

Arkansas Public Service Commission, Application, Docket No. 16-036-FR, July 6, 2018, p. 15.

## B. Florida Power & Light

| Florida Power & Light - MRP | |
|---|---|
| **Term** | Initial Plan: 2006 - 2009 (Docket: 050045-EI, Order No. PSC-05-0902-S-E1)<br><br>Current Plan: 2017-2020 (Docket: 160021-El; Order Approving Settlement) |
| **Approval** | Commission[46] |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Authorized to implement stepwise revenue increases effective January 1, 2017, effective January 1, 2018, and effective on the in-service date of the Okeechobee Unit.[47] Base rates may also be adjusted through a pre-formulated "Solar Base Rate" adjustment, which is contingent upon investment in photovoltaic facilities.[48] |
| **Mandatory Stay-Out?** | If the ROE for FPL falls below 9.6%, FP&L may file with the Commission for an increase in rates.[49] |
| **Mandatory Refiling?** | Rates will be frozen at 2020 levels until a new rate case filed (no mandatory refiling);[50] not required to be under the same plan type. |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: pending petition to Commission and Commission approval. FP&L's authorized ROE covers the range from 9.6% to 11.6%, with rates set using a 10.55% ROE.[51] If FP&L earns a return below this range (according to a monthly earnings surveillance report stated on an FPSC actual, adjusted basis), FP&L may petition the Florida PSC to amend its base |

46 House of Representatives Staff Analysis, HB7071, PCB EUS 17-01.

47 Florida Public Service Commission, Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, December 15, 2016, p. 2.

48 *Ibid.*, p. 3.

49 Florida Public Service Commission, Stipulation and Settlement, Docket No. 160021-EI, October 6, 2016, p. 16.

50 *Ibid.*, p. 11.

51 Florida Public Service Commission, Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, December 15, 2016, p. 3.

| | |
|---|---|
| | rates. Similarly, if FP&L earns a return above this range, any party may petition the PSC to review FP&L's base rates.[52]<br><br>Other Reconciliation: for generation capital expenditures. If actual capital costs for constructing a new unit (the Okeechobee Unit) are less than projected costs, then the lower revenue requirement will be used. If the budget exceeds the projection, FP&L must seek permission to increase the allowed amount.[53] Similarly, the Solar Base Rate Adjustments allows FP&L can invest in up to 1,200 MW of solar generation subject to a cost cap and finding of cost effectiveness.[54] |

52 Florida Public Service Commission, Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, December 15, 2016, pp. 16-17.

53 *Ibid.*, pp. 10, 11.

54 *Ibid.*, p. 1.

# C. Hawai'ian Electric Company

| **Hawai'ian Electric Company - MRP** | |
|---|---|
| **Term** | Initial Plan:<br>- Revenue Decoupling Mechanism Established (Docket: 2008-0274; Final Decision and Order)<br>- 2012-2014 (Docket: 2010-0080; Decision and Order No. 30505)<br><br>Current Plan: 2018-2020 (Docket: 2016-0328; Order No. 35545) |
| **Approval** | Legislative/Commission |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Rate adjustment mechanism ("RAM") with three components that cover O&M, depreciation, and rate base.[55] The total annual change to the RAM is capped and cannot create a change in revenues greater than inflation (as measured by the Gross Domestic Product Price Index) multiplied by base revenues. [56]<br><br>In addition to the RAM, the utility may recover capital expenditures pre-approved by the commission through the Major Projects Interim Recovery ("MPIR") mechanism. The MPIR expenditures are not included in or subject to the RAM cap. |
| **Mandatory Stay-Out?** | Yes; however, HECO may petition its commission to refile early. |
| **Mandatory Refiling?** | Yes; the utilities in Hawai'i follow a three-year general rate case cycle. Required to be under the same plan type. |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: yes, with earnings sharing mechanism through which over-earnings are shared with customers. The earning sharing mechanism has no deadband. 9.5% < ROE < 10.5%, 25% to ratepayers; 10.5% ≤ ROE < 12.5%, 50% to ratepayers; ROE ≥ 12.5%, 90% to ratepayers.[57] |

55 Public Utilities Commission of Hawai'i, Final Decision and Order, Docket No. 2008-0274, August 31, 2010, pp. 71-76.

56 This calculation excludes any revenue for fuel and purchase power expenses or revenues recovered through other surcharge or rate tracking mechanisms, plus RAM revenues less any earnings sharing mechanism credits. See Public Utilities Commission of Hawai'i, Order 32735, Docket No. 2013-0141, March 31, 2015, pp. 5-6, 93-98.

57 Public Utilities Commission of Hawai'i, Final Decision and Order, Docket No. 2008-0274, August 31, 2010, p. 106.

## D. Commonwealth Edison (Illinois)

| Commonwealth Edison (Illinois) – FR | |
|---|---|
| **Term** | Initial Plan: 2012- Ongoing (Docket: 11-0721 and Public Act 098-1175)<br><br>Current Plan: Current (Docket: 18-0808) |
| **Approval** | Legislative: ComEd obtained its formula rate plan as part of the 2011 Energy Infrastructure Modernization Act (EIMA, Act 1652). Under the EIMA provisions, ComEd agreed to meet infrastructure investment targets and to create jobs: $1.3 billion over 5 years in system upgrades, modernization projects, and training facilities, plus $1.3 billion within 10 years in further T&D and smart-grid system upgrades, and 2,000 FTE jobs (or pay penalties for shortfalls in job creation). |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Includes an annual filing setting of the next year's revenue requirement (which includes ROE reconciliation for the prior year, reflecting the difference between the prior year's projected revenue requirement and actual costs incurred, with interest payments on that balance). The Commission reviews the prudence and reasonableness of ComEd's investments before approving the rate base to be used in setting revenue requirement and rates.<br><br>Under the initial law granting formula rate authority, ComEd's FR would be terminated if the average annual rate increase for the years 2012 through 2014 exceeded 2.5%.[58] |
| **Mandatory Stay-Out?** | No |
| **Mandatory Refiling?** | ComEd's formula rate authority is currently in effect until 2022 (extended under the Future Energy Jobs Act (FEJA) legislation of 2017). As of March 12 2019, a bill has been approved by the House Public Utilities Committee to extend ComEd's formula rate authority through 2032.[59] Not required to be under the same plan type. |

58 Under FEJA, there are now rate caps in place for each customer group.

59 Daniels, Steve. "ComEd Asks Springfield to Force You to Make a 13-year Bet on Interest Rates." Crain's Chicago Business. March 15, 2019.

| | |
|---|---|
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: yes; reconciliation of earned ROE around the target (ROE = US T-bond yield monthly average over the previous calendar year + 580 bp).<br><br>Until the most recent rate case, ComEd had a 100 bp collar that set the upper and lower boundaries on the actual earned ROE vs. authorized level (with an offsetting adjustment if the difference lay outside those bounds). However, FEJA authorized ComEd to eliminate the ROE collar deadband to zero bp, which it did (Docket 18-0808).<br><br>The ROE is also subject to penalties (up to 30 bp) for failure to meet certain performance metrics: frequency of total system outages; frequency of "Southern Region" outages; duration of outages; service reliability; number of estimated bills; and, consumption on inactive meters, unaccounted-for-energy, uncollectible expense.<br><br>Initially, the Commission approved use of average rate base for the reconciliations, with interest at a hybrid cost of long- and short-term debt). The ROE reconciliation has since been revised to use year-end rate base, starting with reconciliation of 2011 costs (based on the passage of Senate Bill 9 in 2013). Additionally, interest is now applied at a rate equal to the Illinois Commerce Commission approved pre-tax WACC for the rate year. |

## E. Southwestern Electric Power Company (Louisiana)

| Southwestern Electric Power Company (Louisiana) –FR | |
|---|---|
| **Term** | Initial Plan: 2007-2009 (Docket: U-23327, Subdocket A-A; Order No. U-23327)<br><br>Current Plan: 2014-2017[60] (Docket: U-32220; Order No. U-34200) |
| **Approval** | Commission |
| **Pilot/Transition?** | No; formula rates were first approved for an electric company in Louisiana in 1995 for then Louisiana Power & Light Company (now Entergy Louisiana, LLC).[61] |
| **Annual Base Rate Increases?** | The Formula Rate Plan Rider includes annual rate changes as a result of the ROE reconciliation. |
| **Mandatory Stay-Out?** | Yes; with an exception for extraordinary events as increases or decreases in costs having a net annual revenue requirement impact exceeding $5 million on a Louisiana retail jurisdictional basis and that are classified as force majeure.[62] |
| **Mandatory Refiling?** | Yes; initially required to file prior to December 2018 but received extension to May 31, 2019;[63] not required to be under the same plan type. |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: reconciliation of earned ROE around the target with a +/- 55 bps deadband. If the earned ROE is outside the deadband, the ROE is restored to 60% of the difference between the allowed and earned ROEs. |

60 Temporarily extended through 2018 in Order U-34199.

61 Louisiana Public Service Commission, Order No. U-20925, Docket No. U-20925, June 2, 1995.

62 Southwestern Electric Power Company, Tariff for Electric Service, Effective March 1, 2013, Section B, Formula Rate Plan Rider Schedule FRP, 3.B.

63 Louisiana Public Service Commission, Order No. U-34199, Docket No. U-34199, December 19, 2018, p. 2.

## F. Public Service Company of New Hampshire

| Public Service Company of New Hampshire – MRP | |
|---|---|
| **Term** | July 2010 – June 2015 (Docket: DE 09-035)[64] |
| **Approval** | Judicial; Commission approval for other utility sectors[65] |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Settlement called for "step increases" throughout its term to guard against attrition. PSNH was also permitted to adjust rates, up or down, for Exogenous Events, focused on cost changes from state or federal governments, regulatory cost reassignments, or changes in accounting rules that impact rates by at least $1 million[66] and able to adjust rates if inflation exceeded 4%.[67] |
| **Mandatory Stay-Out?** | PSNH was not permitted to file for a change in base rates ("permanent distribution rates") to come into effect prior to the end of the term unless its 12-month rolling ROE was less than 7% for two consecutive quarters.[68] If all settling parties agreed and the Commission approved, the MRP could also be terminated.[69] |
| **Mandatory Refiling?** | 2015 rates were scheduled to expire at the end of the term[70] and then extended; not required to file under same plan type. |

64 PSNH's rates have been frozen at the 2015 levels as a result of an agreement with its commission related to divestiture of generation facilities. Under this agreement, reliability investments in the distribution system are recovered through a rider. See Eversource Energy's Form 10-K for Fiscal Year Ended December 31, 2018, p. 6.

65 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, pp. 30-31.

66 State of New Hampshire Public Utilities Commission, Settlement Agreement, Docket No. DE-09-035, April 30, 2010, Section 2.2.

67 *Ibid.*, Section 2.3.

68 *Ibid.*, Section 4.4.

69 This portion of the 2010-2015 settlement was not included in the 2016 settlement that continued rates at 2015 levels. See "2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement", June 10, 2015, Section 13.1.

70 State of New Hampshire Public Utilities Commission, Settlement Agreement, Docket No. DE-09-035, April 30, 2010, Section 13.1.

| | |
|---|---|
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: every quarter the company must report its rolling 12-month average ROE for its distribution company; if the ROE exceeds 10%, 75% of the overearnings are returned to customers.[71]<br><br>Other Reconciliation: on changes to the Net Distribution Plan (capital expenditures). PSNH was required to file financial documentation showing actual and forecasted changes to the net distribution utility plant.[72] If the difference between the actual change to the Net Distribution Utility Plant was less than a certain threshold, set on a year-by-year basis, then the actual net utility plant balance was compared to the forecasted. If the net utility balance was below the forecast, the revenue requirement in the next step increase was reduced by the revenue requirement associated with the difference between the forecasted and actual net distribution utility plant.[73] |

71 State of New Hampshire Public Utilities Commission, Settlement Agreement, Docket No. DE-09-035, April 30, 2010, Section 4.1.

72 *Ibid.*, Section 5.2.

73 *Ibid.*, Sections 5.3-5.5.

# G. Public Service Company of New Mexico

| Public Service Company of New Mexico - FTY | |
|---|---|
| **Term** | Initial Plan: 2016-2017 (Docket: 15-00261-UT; Final Order Partially Adopting Corrected Recommended Decision)<br><br>Current Plan: 2018-2019 (Docket: 16-00276-UT, Order on Notice of Acceptance) |
| **Approval** | Legislative[74] |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Increase in retail non-fuel base rate revenues to be implemented in two phases. The total increase amount is based on a non-fuel revenue requirement from a test period of January 1 through December 31, 2018. The first increase will be implemented on February 1, 2018 ("Phase I") and the second increase will occur on January 1, 2019 ("Phase II").[75] |
| **Mandatory Stay-Out?** | PSNM is not allowed to make non-fuel base rate changes with an effective date prior to Jan. 1, 2020.[76] |
| **Mandatory Refiling?** | No |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: PSNM is required to return all earnings over the allowed ROE plus 50 bps to customers through a renewable energy rider that pre-dates the use of a future test year.[77] |

74 Senate Bill 477 ("SB 477") was passed by the New Mexico legislature and became effective in June 2009 (PNM 2012 10-K, p. A-4)

75 New Mexico Public Regulation Commission, Modified Revised Stipulation, Case No. 16-00276-UT, p. 4 section A.1.

76 *Ibid.*, p. 7.

77 Public Service Company of New Mexico's Form 10-K for Fiscal Year Ended December 31, 2018, p. A-3.

## H. Consolidated Edison (New York)

| Consolidated Edison (New York) - MRP | |
|---|---|
| **Term** | Initial Plan: 1992-1995 (Docket: 91-E-0462; Order: Opinion 92-8)<br><br>Current Plan: 2017-2019 (Docket: 16-E-0060) |
| **Approval** | Commission |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Includes an Attrition Relief Mechanism (ARM) based on company forecasts, which include inflation increases as well as modifications for known changes. |
| **Mandatory Stay-Out?** | The New York PSC may allow Con Ed to refile if it deems that circumstances exist that, in the judgement of the Commission, threaten the utility's economic viability or the ability to maintain safe, reliable service.[78] |
| **Mandatory Refiling?** | No; however, if the company does not file for new rates, it must make a compliance filing by December 1, 2019 to adjust the 2019 rates for 2020 (due to use of levelization in the 2016-2019 term). Required to file under the same plan type (since New York adopted a three year general rate case cycle in 1983).[79] |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: for overearnings only. Target ROE and Deadband: 9.0%; +/- 50 bps deadband. Overearnings sharing: 9.5% ≤ ROE < 10% 50% to ratepayers; 10% ≤ ROE < 10.5% 75% to ratepayers; 10.5% ≤ ROE 90% to ratepayers<br><br>Other Reconciliation: CapEx and OpEx reconciliation. For OpEx, the commission will reconcile projections for approximately 20 line-items including property taxes, contractor costs, pensions and other post-employment benefits, environmental remediation, long term debt costs, and a portion of managerial pay. For the majority of the aforementioned categories, the credits or surcharges resulting from the reconciliation will be deferred over the term of the plan and revenue requirement impacts |

78 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 115.

79 Matthew Wald, "Con Ed Nears Rate Increase In 3-Year Plan," New York Times. February 11, 1992.

| | |
|---|---|
| | addressed in future rate proceedings.[80] For CapEx, the commission will reconcile based on net plant balances. If the company underinvests based on net plant balances on average across the three years, the revenue requirement will be deferred for ratepayers.[81] |

80 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 35.

81 *Ibid.*, pp. 28-29.

# I. Northern States Power (North Dakota)

| Northern States Power (North Dakota) - MRP | |
|---|---|
| **Term** | 2013-2016 (Docket: PU-12-0813; Order Adopting Settlement) |
| **Approval** | Commission |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | 4.9% rate increases in 2013, 2014, and 2015[82] |
| **Mandatory Stay-Out?** | May not refile prior to November 1, 2016 with the potential to seek additional revenues under a force majeure clause (impact of at least $1.5 million to the revenue requirement).[83] |
| **Mandatory Refiling?** | No |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: allowed ROE increased over time (9.75% (2013), 10% (2014), 10%, (2015), and 10.25% (2016)).[84] NSP was required to share 50% of all overearnings with customers. |

82 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, p. 5.

83 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, pp. 6-7.

84 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, Order adopting settlement p. 5.

# J. Puget Sound Energy (Washington)

| J. Puget Sound Energy (Washington) – MRP | |
|---|---|
| **Term** | 2013-2016 (Docket: UE-121697; Order No. 07) |
| **Approval** | Commission |
| **Pilot/Transition?** | No |
| **Annual Base Rate Increases?** | Fixed 3% escalation of allowed revenue per year. |
| **Mandatory Stay-Out?** | Yes[85] |
| **Mandatory Refiling?** | Yes;[86] not required to be under the same plan type. |
| **Reconciliation between Actual and Forecasts** | ROE Reconciliation: all earned returns above the allowed ROE are shared 50/50 between ratepayers and the utility.<br>Other Reconciliation: no; although PSE's decoupling plan included a reconciliation for allowed revenues per customer, this is not a reconciliation related to PSE's costs but strictly to its revenues. |

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85 Washington Utilities and Transportation Commission, Order 07, Docket Nos. UE-121697 and UG-121705 (consolidated) and Docket Nos. UE-130137 and UG-130138 (consolidated), June 25, 2013, p. 4.

86 *Ibid.*

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# Alternative Regulation for Emerging Utility Challenges: 2015 Update

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Prepared for:
Edison Electric Institute

**November 11, 2015**

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# Contents

# I. Introduction

Investor-owned electric utilities in the United States are buffeted today by varied and rapid changes in the business conditions they face. For vertically integrated electric utilities ("VIEUs") and utility distribution companies ("UDCs") alike, the traditional cost of service approach to rate regulation is often not ideal for helping utilities cope with these changes. Alternative approaches to regulation ("Altreg") can often help utilities secure better outcomes for their customers and shareholders.

The changing business climate stems primarily from three root causes. One is pressure, from policymakers and many customers, for the power industry to lighten its environmental footprint. In addition to evolving renewable portfolio standards at the state level, utilities must comply with an array of federal initiatives such as the Environmental Protection Agency's Clean Power Plan. Demand-side management ("DSM") programs and tightening building codes and appliance standards encourage energy efficiency. Some customers seek power from greener sources than the increasingly clean portfolios of utilities. Self generation from rooftop solar is one means to this end, and its cost is falling. Customer-sited distributed generation ("DG") must be accommodated, and utilities must purchase power surpluses that these facilities generate at regulated rates.

A second force for change is technological progress in metering and distribution. Advanced metering infrastructure and other smart grid technologies can improve reliability and facilitate integration of intermittent renewables. Time-sensitive pricing can encourage customers to use the grid in less costly ways. New value-added optional products and services can be offered which benefit customers.

A third force for change is increased concern about the reliability and resiliency of grid service. Some facilities are approaching advanced age, and some need more protection from severe weather. Many customers seek better quality service.

These forces are having important practical effects on utilities. Growth in the demand for their traditional services has slowed, and utilities face competition from distributed energy resources ("DERs"). Nevertheless, some utilities need capital expenditures ("capex") for cleaner generating capacity, smart grid facilities, increased resiliency, and replacement of aging assets. Many new facilities don't automatically trigger revenue growth. Increased marketing flexibility is needed to meet competitive challenges and complex, changing customer needs.

Under traditional regulation, the base rates that compensate utilities for costs of non-energy inputs are reset only in general rate cases with historical test years. These lengthy proceedings require a detailed review of all costs and their allocation amongst the utility's retail services. Revenue from secondary sources (e.g., off-system sales) is imputed against the revenue requirement.

Most base rate revenue is drawn from volumetric and other usage charges. Since the cost of base rate inputs is driven more by capacity than system use in the short run, a utility's finances are sensitive between rate cases to the gap between growth in system use and capacity. A convenient proxy for this gap is the growth in use per customer (aka "average use"). The need for rate cases increases when average use declines.

Traditional regulation is ill-suited for addressing many of today's challenges. Growth in average use was once positive, and the resulting incremental revenues helped utilities finance rising cost without rate cases. Today, growth in the average use of residential and commercial customers is typically static and often negative. Utilities needing normal or high capital expenditures are then compelled to file rate cases more frequently. These involve high regulatory cost and are nonetheless frequently uncompensatory when they involve historical test years. Frequent rate cases also reduce utility opportunities to increase earnings from improved cost containment and marketing. Traditional regulation also does not allow for many value-added or optional rates and services. Improved utility performance is thus discouraged at a time when it is increasingly needed to respond to competitive pressures.

Increased financial attrition has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, can involve sweeping regulatory change. Others, like revenue decoupling and cost trackers, target specific challenges.

This survey, now updated to include precedents through mid-2015, explains Altreg options and details precedents in the regulation of retail electric utility rates. A summary of states that currently use these approaches is featured in Table 1. Information is also provided on precedents for gas and water distributors and for energy utilities in Australia, Canada, and Britain. This year's survey also discusses marketing flexibility, a new Altreg area of growing interest to EEI members.

Figure 1

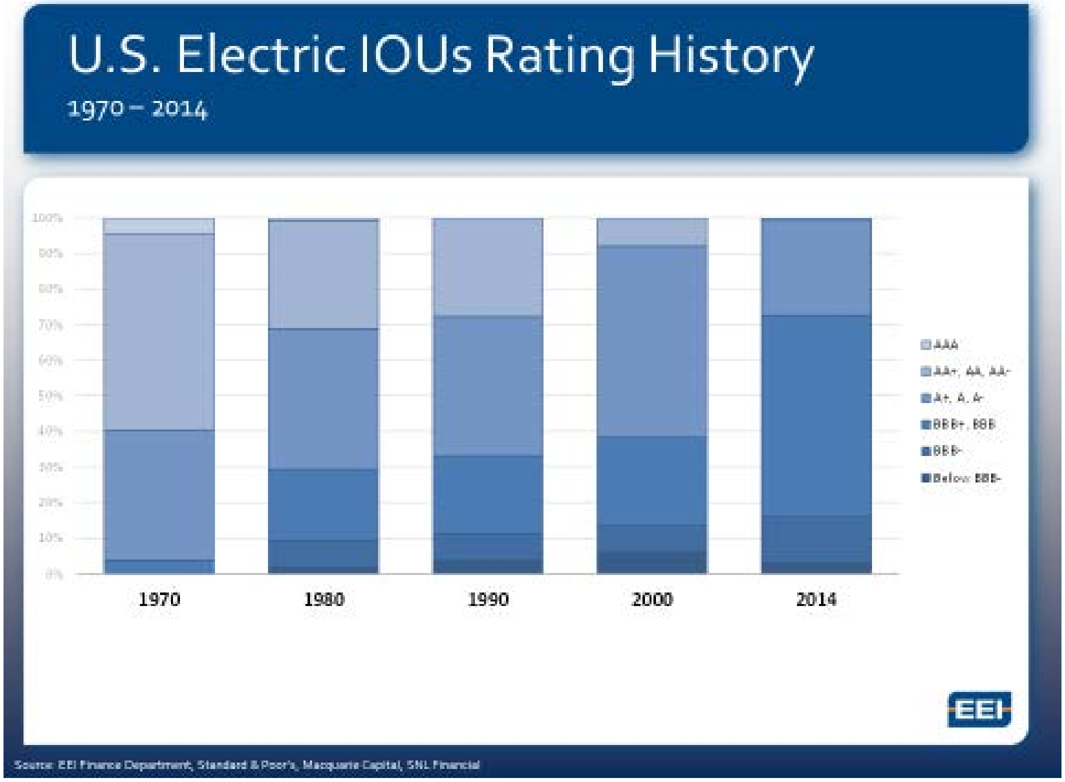
U.S. Electric IOUs Rating History
1970 – 2014
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1970
1980
1990
2000
2014
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
Below BBB-
EEI
Source: EEI Finance Department, Standard & Poor's, Macquarie Capital, SNL Financial

Table 1

# Alternative Regulation Tools: An Overview of Current Precedents

| State | Capital Cost Trackers | Measures that Relax the Use/Revenue Link | | | Multiyear Rate Plans[1] | Retail Formula Rate Plans | Forward Test Years |
|---|---|---|---|---|---|---|---|
| | | Decoupling True Up Plans | Lost Revenue Adjustment Mechanisms | Fixed Variable Retail Pricing | | | |
| Alabama | Electric & Gas | | | | | Electric & Gas | Yes |
| Alaska | | | | | | | |
| Arizona | Electric, Gas, & Water | Gas only | Electric & Gas | | Electric only | | |
| Arkansas | Electric & Gas | Gas only | Electric & Gas | | | | |
| California | Electric & Gas | Electric & Gas | | | Electric & Gas | | Yes |
| Colorado | Electric & Gas | | | | Electric only | | |
| Connecticut | Electric, Gas, & Water | Electric & Gas | Gas only | Electric & Gas | | | Yes |
| Delaware | Electric, Gas, & Water | | | | | | |
| District of Columbia | Electric & Gas | Electric only | | | | | |
| Florida | Electric & Gas | | | Gas only | Electric only | | Yes |
| Georgia | Electric & Gas | Gas only | | Gas only | Electric only | Gas only | Yes |
| Hawaii | Electric only | Electric only | | | Electric only | | Yes |
| Idaho | Electric only | Electric only | | | | | |
| Illinois | Gas & Water | Gas only | | Electric & Gas | | Electric only | Yes |
| Indiana | Electric, Gas, & Water | Gas only | Electric only | | Gas only | | |
| Iowa | Gas only | | | Gas only | Electric only | | |
| Kansas | Gas only | | Electric only | Gas only | | | |
| Kentucky | Electric & Gas | | Electric & Gas | Gas only | | | Yes |
| Louisiana | Electric only | | Electric only | | Electric only | Electric & Gas | Yes |
| Maine | Electric, Gas, & Water | Electric only | | Gas only | Gas only | | Yes |
| Maryland | Electric & Gas | Electric & Gas | | | | | |
| Massachusetts | Electric & Gas | Electric & Gas | Electric & Gas | | Gas only | | |
| Michigan | Gas only | Gas only | | | | | Yes |

Table 1 continued

| State | Capital Cost Trackers | Measures that Relax the Use/Revenue Link | | | Multiyear Rate Plans[1] | Retail Formula Rate Plans | Forward Test Years |
|---|---|---|---|---|---|---|---|
| | | Decoupling True Up Plans | Lost Revenue Adjustment Mechanisms | Fixed Variable Retail Pricing | | | |
| Minnesota | Electric & Gas | Electric & Gas | | | | | Yes |
| Mississippi | Electric & Gas | | Electric & Gas | Electric only | | Electric & Gas | Yes |
| Missouri | Gas & Water | | | Gas only | | | |
| Montana | Electric & Gas | | Gas only | | | | |
| Nebraska | Gas only | | | Gas only | | | |
| Nevada | Gas only | Gas only | Electric only | | | | |
| New Hampshire | Electric, Gas, & Water | | | Gas only | Electric & Gas | | |
| New Jersey | Electric, Gas, & Water | Gas only | | | | | |
| New Mexico | | | | | | | Yes |
| New York | Gas & Water | Electric & Gas | Gas only | Electric & Gas | Electric & Gas | | Yes |
| North Carolina | Gas & Water | Gas only | Electric only | | | | |
| North Dakota | Electric only | | | Gas only | Electric only | | Yes |
| Ohio | Electric, Gas, & Water | Electric only | Electric only | Gas only | Electric only | | |
| Oklahoma | Electric only | | Electric only | Electric & Gas | | Gas only | |
| Oregon | Electric & Gas | Electric & Gas | Electric & Gas | | | | Yes |
| Pennsylvania | Electric, Gas, & Water | | | Gas only | | | Yes |
| Rhode Island | Electric & Gas | Electric & Gas | | | | | Yes |
| South Carolina | Electric only | | Electric only | | | Gas only | |
| South Dakota | Electric only | | | | | | |
| Tennessee | Gas only | Gas only | | Gas only | | Gas only | Yes |
| Texas | Electric & Gas | | | Gas only | | Gas only | |
| Utah | Gas only | Gas only | | | | | Yes |
| Vermont | | | | Gas only | | | |
| Virginia | Electric & Gas | Gas only | | Gas only | Electric only | | |
| Washington | Gas only | Electric & Gas | | | Electric & Gas | | |
| West Virginia | Electric only | | | | | | |
| Wisconsin | | | | Gas only | | | Yes |
| Wyoming | Electric only | Gas only | Electric & Gas | Electric & Gas | | | Yes |

[1] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

# II. Cost Trackers

A cost tracker is a mechanism for expedited recovery of specific utility cost (e.g., outside of a rate case). Balancing accounts are typically used to track unrecovered costs. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are more practical than rate cases for addressing particular costs. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent rate cases and materially impact utility risk. Other volatile expenses that are sometimes addressed with trackers include those for pensions, severe storms, and uncollectible bills.

A second use of trackers is for costs incurred due to policies of government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agencies to consider the impact of their policies on customer bills.

Trackers are also used to compensate utilities for costs that are rapidly rising and don't otherwise trigger new revenue, whether or not they are volatile or mandated. This encourages needed expenditures and reduces risk and the frequency of rate cases. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in large measure to their rapid growth include those for health care.

Trackers for some costs have multiple rationales. DSM expenses, for example, are often sizable and sometimes grow rapidly.[1] Utility DSM programs are often mandated. Additionally, DSM can slow growth in the average use of power and reduce the need for plant additions, important sources of earnings growth for utilities. Tracking DSM expenses helps to balance utility incentives to embrace DSM.

Capital cost trackers typically address the accumulating depreciation, return on asset value, and taxes that result from the capex.[2] Capital costs can qualify for tracker treatment on several grounds. Major plant additions are volatile. Capex might be necessitated by highway construction or changes in government safety, reliability, or environmental standards. Capex is sometimes large enough to cause brisk cost growth that would otherwise occasion frequent rate cases.

An early use of capital cost trackers in the electric utility industry was to address construction costs of large power plants. These plants can take years to construct. An allowance in rates for a return on funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery of the allowance strains utility cash flow, increases financing expenses, and induces more rate "shock" when the value of the plant and construction financing is finally added to the rate base.

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[1] This survey only documents capital cost trackers. Trackers for DSM expenses are ubiquitous so that there is less need for documentation.

[2] Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Many commissions have addressed these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers have often been used in lieu of frequent rate cases to obtain CWIP recovery.

Capital costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for large generation units, and construction of specific assets usually takes less than a year. However, the capex can still be sizable and doesn't automatically trigger new revenue when completed. A tracker for accelerated modernization costs can help a company modernize its grid and improve its services without frequent rate cases.

Capital costs of generation emissions controls are often accorded tracker treatment. These controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities typically become used and useful each year over a series of years.

There are varied treatments of costs in approved capital trackers. Regulators often approve tracked capex budgets in advance, usually after considerable deliberation. Procedures for reviewing the need for generation plant additions are especially well established. Once a budget is set, the treatment of variances between actual and budgeted cost becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (e.g., 50-50) between the utility and its customers. Utilities are also permitted sometimes to share in the benefits of capex underspends. The prudence of tracked capex is often subject to a final review when the cost is added to rate base, a step that usually occurs in the next rate case.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are numerous and continue to grow. This is the most widely used Altreg tool in the United States. For electric utilities, trackers for emissions controls, generation capacity, advanced metering infrastructure, and general system modernization have been especially common in recent years. Trackers for gas distributors typically address the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common for accelerated modernization.

Figure 2: Recent Capital Cost Tracker Precedents by State: Energy Utilities

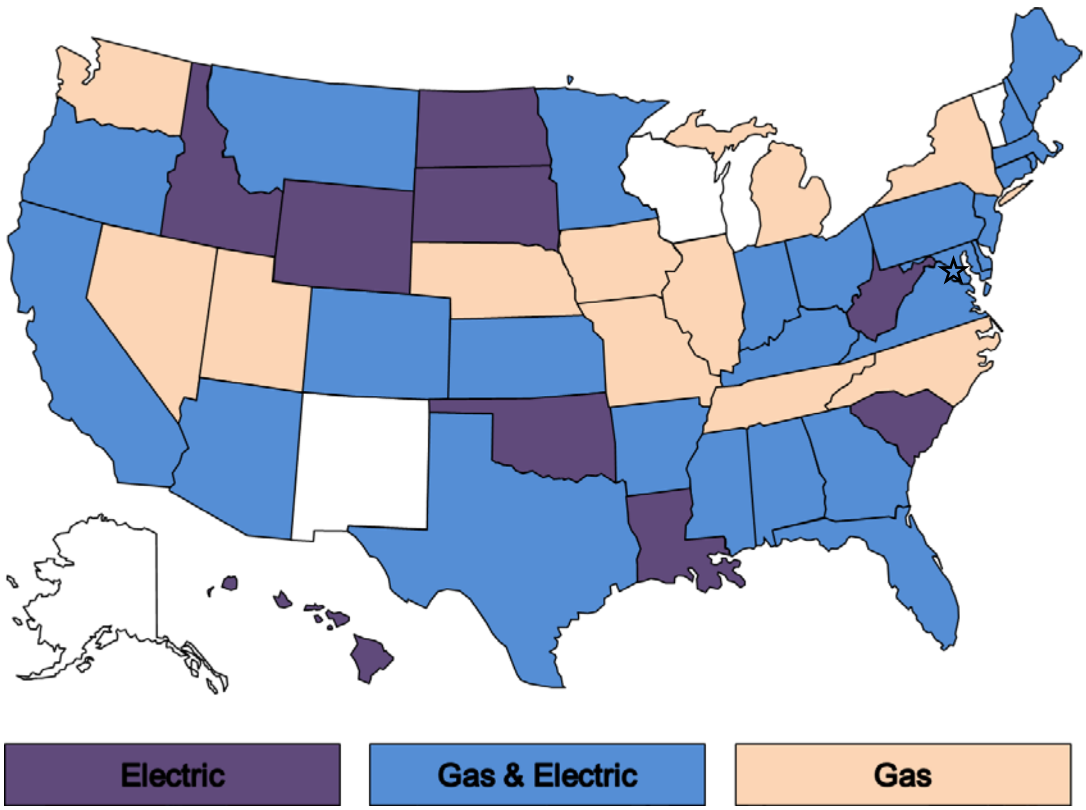


Figure 3: Recent Capital Cost Tracker Precedents by State: Water Utilities

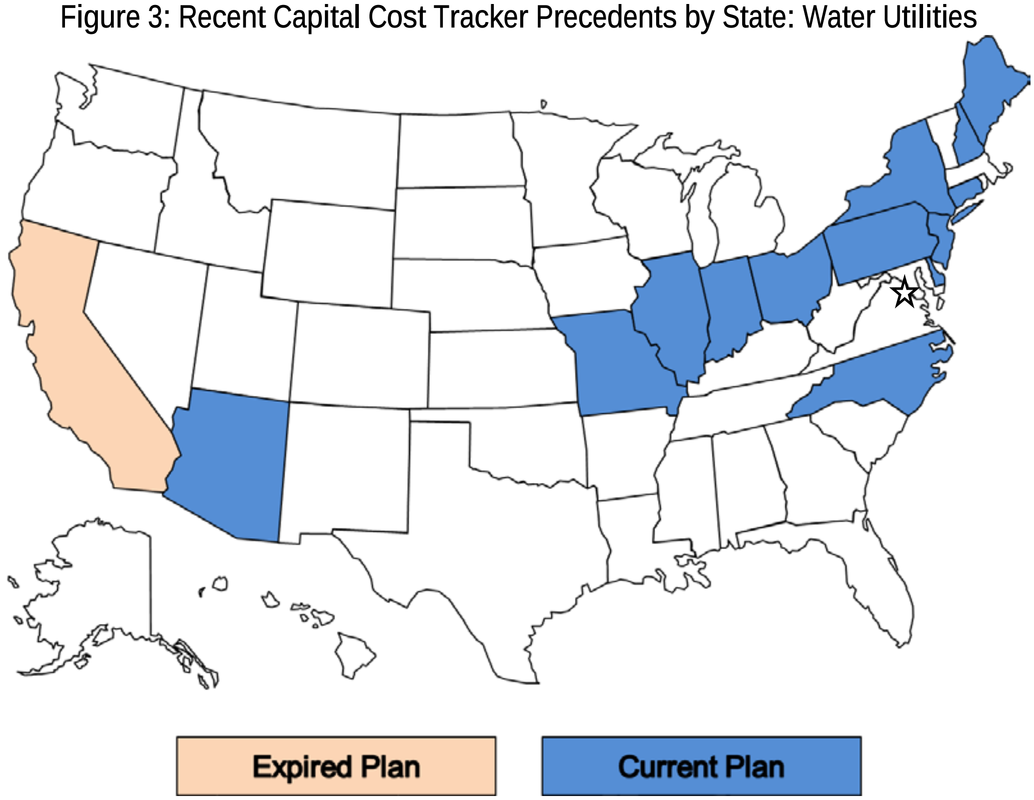

Table 2

# Recent Capital Cost Tracker Precedents

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| AL | Alabama Power | Electric | Rate Certificated New Plant | Any approved by Commission through CPCN | Dockets 18117 and 18416 (November 1982) |
| AL | Mobile Gas Service | Gas | Cast Iron Replacement Factor | Replacement of cast iron mains | Docket 24794 (November 1995) |
| AR | Arkansas Oklahoma Gas | Gas | Act 310 Surcharge | Relocations of pipelines mandated by government agencies | Docket 12-088-U (July 2013) |
| AR | Arkansas Oklahoma Gas | Gas | System Safety Enhancement Rider | Replacement of bare steel mains, mains on low pressure systems, mains that are subject of an advisory notice by government that company deems to be unsatisfactory | Docket 13-078-U (July 2014) |
| AR | CenterPoint Energy Arkla | Gas | Main Replacement Rider | Replacement of cast iron and bare steel mains and services | Docket 06-161-U (October 2007) |
| AR | CenterPoint Energy Arkla | Gas | Government Mandated Expenditure Surcharge Rider | Replacements resulting from highway and street rebuilding | Docket 10-108-U (March 2011) |
| AR | Empire District Electric | Electric | Alternative Generation Environmental Recovery Rider | Environmental | Docket 15-010-U (August 2015) |
| AR | Oklahoma Gas & Electric | Electric | Smart Grid Rider | Systemwide smart grid implementation | Docket 10-109-U (August 2011) |
| AR | SourceGas Arkansas | Gas | At-Risk Meter Relocation Program Rider | Installation of new services for meters relocated due to motor vehicle collision risk | Docket 13-079-U (July 2014) |
| AR | SourceGas Arkansas | Gas | Main Replacement Program Rider | Replacement of bare steel and coated steel mains, mains that are subject of an advisory notice by government that company deems to be unsatisfactory, and associated services | Docket 13-079-U (July 2014) |
| AR | SourceGas Arkansas | Gas | Act 310 Surcharge | Bare steel and cast iron pipeline replacement, in-line inspection project, emissions controlling catalysts for compressor station engines, greenhouse gas monitoring of some regulator stations, highway relocation projects | Docket 13-072-U (April 2014) |
| AR | SWEPCO | Electric | Alternative Generation Recovery Rider | New generation | Docket 09-008-U (November 2009) |
| AR | SWEPCO | Electric | Rider Environmental Compliance Surcharge | Environmental | Docket 15-021-U (October 2015) |
| AZ | Arizona Public Service | Electric | Renewable Energy Standard Adjustment Schedule | Renewables not recovered in base rates | Docket E-01345A-08-0172 |
| AZ | Arizona Public Service | Electric | Environmental Improvement Surcharge | Environmental improvement projects | Docket E-01345A-11-0224 (May 2012) |
| AZ | Arizona Public Service | Electric | Four Corners Rate Rider Surcharge | Generation | Docket E-01345A-11-0224 (December 2014) |
| AZ | Arizona Water Company | Water | Arsenic Cost Recovery Mechanism | Investments to reduce arsenic in water supply | Various (operating regions have separate decisions approving ACRMs) |
| AZ | Arizona Water Company - Eastern Group | Water | System Improvement Benefits Mechanism | Replacement of leak prone mains and related services, meters, and hydrants, replace meters that do not have lead free brass, other replacements for mains, services, meters, and hydrants that are at the end of their useful life | Decision 73938 (June 2013) |
| AZ | Southwest Gas | Gas | Customer Owned Yard Line Cost Recovery Mechanism | Replacement and ownership of customer-owned yard lines that have been shown to be leaking | Docket G-01551A-10-0458 (January 2012) |
| AZ | Tucson Electric Power | Electric | Environmental Compliance Adjustor | Miscellaneous environmental projects | Decision 73912 (June 2013) |
| CA | Pacific Gas & Electric | Electric | Smart Grid Memorandum Account | Smart grid projects that received DOE matching funds | Decision 09-09-029 (September 2009) |
| CA | Pacific Gas & Electric | Gas Transmission | Pipeline Safety Implementation Plan | Pipeline replacement, automated valve installation, and upgrades to pipeline | Decision 12-12-030 (December 2012) |
| CA | Pacific Gas & Electric | Electric | Smart Grid Pilot Deployment Project Balancing Account | Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement | Decision 13-03-032 (March 2013) |
| CA | San Diego Gas & Electric | Electric & Gas | Advanced Metering Infrastructure Balancing Account | AMI | Decision 07-04-043 (April 2007) |
| CA | San Diego Gas & Electric | Electric | Energy Storage Balancing Account | Projects to store solar energy | Decision 13-05-010 (May 2013) |
| CA | San Diego Gas & Electric | Gas | Post-2011 Distribution Integrity Management Program Balancing Account | DIMP related costs | Decision 13-05-010 (May 2013) |
| CA | San Diego Gas & Electric | Gas | Transmission Integrity Management Program Balancing Account | TIMP related costs | Decision 13-05-010 (May 2013) |
| CA | San Diego Gas & Electric | Gas Transmission | Safety Enhancement Capital Cost Balancing Account | Replacement of mains that fail pressure tests or that cannot be pressure tested | Decision 14-06-007 (June 2014) |
| CA | Southern California Edison | Electric | SmartConnect Balancing Account | Advanced metering infrastructure project | Decision 08-09-039 (September 2008) |
| CA | Southern California Edison | Electric | Solar PV Balancing Account | Solar generation | Decision 09-06-049 (June 2009) |
| CA | Southern California Gas | Gas | Advanced Metering Infrastructure Balancing Account | AMI | Decision 10-04-027 (April 2010) |
| CA | Southern California Gas | Gas | Post-2011 Distribution Integrity Management Program Balancing Account | DIMP related costs | Decision 13-05-010 (May 2013) |
| CA | Southern California Gas | Gas | Transmission Integrity Management Program Balancing Account | TIMP related costs | Decision 13-05-010 (May 2013) |
| CA | Southern California Gas | Gas Transmission | Safety Enhancement Capital Cost Balancing Account | Replacement of mains that fail pressure tests or that cannot be pressure tested | Decision 14-06-007 (June 2014) |
| CO | Black Hills Colorado Electric | Electric | Transmission Cost Adjustment Rider | Transmission projects | Docket 09-014E, Decision C09-0271 (March 2009) |
| CO | Black Hills Colorado Electric | Electric | Clean Air Clean Jobs Act Rider | Gas-fired generation | Docket 14AL-0393E, Decision C14-1504 (December 2014) |
| CO | Public Service Company of Colorado | Electric | Transmission Cost Adjustment | Transmission projects | Docket 07A-339E, Decision C07-1085 (December 2007) |
| CO | Public Service Company of Colorado | Gas | Pipeline Safety Integrity Adjustment | Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements | Docket 10-AL-963G (August 2011) |

# Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| CO | Public Service Company of Colorado | Electric | Clean Air Clean Jobs Act Rider | Miscellaneous environmental projects including gas-fired generation, scrubbers | Proceeding 14A-680E, Decision C15-0292 (March 2015) |
| CO | Rocky Mountain Gas | Gas Transmission | System Safety and Integrity Rider | TIMP, DIMP, and other safety regulatory compliance projects | Docket 13AL-0046G, Decision R14-0114 (February 2014) |
| CT | Aquarion Water Company of Connecticut | Water | Water Infrastructure and Conservation Adjustment | Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended | Docket 08-06-21WI01 (December 2008) |
| CT | Connecticut Light & Power | Electric | System Resiliency Plan | Structural hardening | Docket 12-07-06 (January 2013) |
| CT | Connecticut Natural Gas | Gas | System Expansion Reconciliation Mechanism | System expansion | Docket 13-06-02 (November 2013) |
| CT | Connecticut Natural Gas | Gas | DIMP True-Up Mechanism | Cast iron and bare steel main replacement | Docket 13-06-08; (January 2014) |
| CT | Connecticut Water | Water | Water Infrastructure and Conservation Adjustment | Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended | Docket 08-10-15WI01 (March 2009) |
| CT | Southern Connecticut Gas | Gas | System Expansion Reconciliation Mechanism | System expansion | Docket 13-06-02 (November 2013) |
| CT | Torrington Water | Water | Water Infrastructure and Conservation Adjustment | Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended | Docket 09-06-17WI01 (December 2009) |
| CT | United Water Connecticut | Water | Water Infrastructure and Conservation Adjustment | Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended | Docket 09-06-17WI01 (December 2009) |
| CT | Yankee Gas Services | Gas | System Expansion Reconciliation Mechanism | System expansion | Docket 13-06-02 (November 2013) |
| DC | Potomac Electric Power | Electric | Underground Project Charge | Undergrounding of specific feeders | Formal Case 1116 (November 2014) |
| DC | Washington Gas Light | Gas | Plant Recovery Adjustment | Remediation/replacement of mechanical couplings | Formal Case 1027 (December 2009) |
| DC | Washington Gas Light | Gas | Accelerated Pipe Replacement Plan Adjustment | Replacement of cast iron mains, bare steel mains and services and "black plastic" services | Formal Case 1115 (January 2015) |
| DE | Artesian Water | Water | Distribution System Improvement Charge | Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 01-474 (December 2001) |
| DE | Delmarva Power & Light | Gas | Utility Facility Relocation Charge | Replacements due to mandated relocations that are not otherwise reimbursed | Docket 12-546 (October 2013) |
| DE | Delmarva Power & Light | Electric | Utility Facility Relocation Charge | Replacements due to mandated relocations that are not otherwise reimbursed | Docket 13-115 (August 2014) |
| DE | Sussex Shores Water | Water | Distribution System Improvement Charge | Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 01-470 (December 2001) |
| DE | Tidewater Utilities | Water | Distribution System Improvement Charge | Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 03-210 (May 2003) |
| DE | United Water Delaware | Water | Distribution System Improvement Charge | Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 01-481 (December 2001) |
| FL | Chesapeake Utilities | Gas | Gas Reliability Infrastructure Program Tariff | Replacement of bare steel mains and services | Docket 120036-GU (September 2012) |
| FL | Florida City Gas | Gas | Safety and Access Verification Expedited Program | Replacement of unprotected steel mains, relocation of certain gas mains in rear lot easements | Docket 150116-GU (September 2015) |
| FL | Florida Power and Light | Electric | Environmental Cost Recovery Clause | Miscellaneous environmental projects | Docket 080281-EI (August 2008) |
| FL | Florida Power and Light | Electric | Capacity Cost Recovery Clause | Nuclear power | Docket 090009-EI (November 2009) |
| FL | Florida Power and Light | Electric | Generation Base Rate Adjustment | Generation | Docket 120015-EI (December 2012) |
| FL | Florida Public Utilities | Gas | Gas Reliability Infrastructure Program Tariff | Replacement of bare steel mains and services | Docket 120036-GU (September 2012) |
| FL | Gulf Power | Electric | Environmental Cost Recovery Clause | Miscellaneous environmental projects | Docket 930613-EI (January 1994) |
| FL | Peoples Gas System | Gas | Cast Iron/Bare Steel Replacement Rider | Replacement of bare steel and cast iron pipes | Docket 110320-GU (September 2012) |
| FL | Progress Energy Florida | Electric | Environmental Cost Recovery Clause | Miscellaneous environmental projects | Docket 050078-EI (September 2005) |
| FL | Progress Energy Florida | Electric | Capacity Cost Recovery Clause | Nuclear power | Docket 090009-EI (November 2009) |
| FL | Progress Energy Florida | Electric | Generation Base Rate Adjustment | Generation | Docket 130208 (November 2013) |
| FL | Tampa Electric | Electric | Environmental Cost Recovery Clause | Miscellaneous environmental projects | Docket 960688-EI (August 1996) |
| GA | Atlanta Gas Light | Gas | Pipeline Replacement Program Cost Recovery Rider | Replacement of cast iron and bare steel pipe | Docket 29950 as STRIDE tracker in 2009 |
| GA | Atlanta Gas Light | Gas | Strategic Infrastructure Development and Enhancement Surcharge | Pre-1985 plastic mains and services replacement, planned customer expansions, and infrastructure improvements that sustain reliability and operational flexibility | Docket 8516-U and 29950 (October 2009 and August 2013) |
| GA | Atmos Energy (now Liberty Utilities) | Gas | Pipe Replacement Surcharge | Replace cast iron and bare steel pipe | Docket 12509-U (December 2000) |
| GA | Georgia Power Company | Electric | Environmental Compliance Cost Recovery | Miscellaneous environmental projects | Docket 25060-U (December 2007) |
| GA | Georgia Power Company | Electric | Nuclear Construction Cost Recovery | Nuclear generation | Docket 27800, Senate Bill 31 |
| HI | Hawaii Electric Light | Electric | Renewable Energy Infrastructure Program Surcharge | Renewable energy infrastructure | Docket 2007-0416 (December 2009) |
| HI | Hawaiian Electric Company | Electric | Renewable Energy Infrastructure Program Surcharge | Renewable energy infrastructure | Docket 2007-0416 (December 2009) |
| HI | Maui Electric | Electric | Renewable Energy Infrastructure Program Surcharge | Renewable energy infrastructure | Docket 2007-0416 (December 2009) |
| IA | Black Hills Energy | Gas | System Safety Maintenance Adjustment | Replacement of steel and pvc pipe, relocations mandated by local governments | Docket RPU-2012-0004 (March 2013) |
| ID | PacifiCorp | Electric | Energy Cost Adjustment Mechanism | Lake Side II generation facility | Case PAC-E-13-04 (October 2013) |

## Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| IL | Ameren Illinois | Gas | Rider Qualifying Infrastructure Plant | Replacement of prone to leak distribution and transmission pipe, installation of AMI and communications infrastructure, replacing or installing transmission or distribution facilities to establish over-pressure protection, replacement of difficult to locate mains and services, replacement of high pressure transmission pipelines without a recorded maximum allowable operating pressure, replacements to facilitate an upgrade from a low pressure system to a high pressure system | Docket 14-0573 (January 2015) |
| IL | Consumers Illinois Water Company (Kankakee, Vermilion, Woodhaven Districts) | Water | Qualifying Infrastructure Plant Surcharge Rider | Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 01-0561 (December 2001) |
| IL | Illinois-American Water (Chicago Metro Division) | Water | Qualifying Infrastructure Plant Surcharge Rider | Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 09-0251 (March 2010) |
| IL | Illinois-American Water (Single Tariff Pricing Zone) | Water | Qualifying Infrastructure Plant Surcharge Rider | Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 04-0336 (December 2004) |
| IL | Northern Illinois Gas | Gas | Rider Qualifying Infrastructure Plant | Replacement of cast iron pipe, non-cast iron pipe, and copper services; relcoation of meters from inside customers' premises; upgrading of system from low pressure to medium pressure; replacement or installation of regulator stations, regulators, valves and associated facilities to establish over-pressure protection | Docket 14-0292 (July 2014) |
| IL | Peoples Gas Light & Coke | Gas | Rider Qualifying Infrastructure Plant | Replacement of cast and ductile iron, relcoation of meters from inside customers' premises, upgrading of system from low pressure to medium pressure, replacement of high pressure transmission pipelines at higher risk of failure or lacking records, installation of regulator stations to establish over-pressure protection | Docket 13-0534 (January 2014) |
| IN | Duke Energy Indiana | Electric | Qualified Pollution Control Property | Miscellaneous environmental projects | Cause 41744 (February 2001) |
| IN | Duke Energy Indiana | Electric | Integrated Coal Gasification Combined Cycle Generating Facility Revenue Recovery Adjustment | Integrated gasification combined cycle generating plant | Docket 43114 (November 2007) |
| IN | Indiana Michigan Power | Electric | Clean Coal Technology Rider | Miscellaneous environmental projects | Cause 43636 (June 2009) |
| IN | Indiana Water Service | Water | Distribution System Improvement Charge | Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants) | Cause 42743 DSIC-1 (December 2004) |
| IN | Indiana-American Water | Water | Distribution System Improvement Charge | Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants) | Cause 42351 DSIC-1 (February 2003) |
| IN | Indianapolis Power & Light | Electric | Environmental Compliance Cost Recovery | Miscellaneous environmental projects | Cause 42170 (November 2002) |
| IN | Northern Indiana Public Service | Electric | Environmental Cost Recovery Mechanism | Miscellaneous environmental projects | Cause 42150 (November 2002) |
| IN | Northern Indiana Public Service | Electric | Transmission, Distribution & Storage System Improvement Charge | Investments to maintain the capacity deliverability of system and replacement of aging infrastructure, economic development | Cause 44370 and 44371 (February 2014) |
| IN | Northern Indiana Public Service | Gas | Distribution System Improvement Charge | Gas system deliverability and system integrity projects, rural main extensions | Cause 44403 TDSIC 1 (January 2015) |
| IN | Utility Center Inc. | Water | Distribution System Improvement Charge | Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants) | Docket 42416 DSIC-1 (June 2003) |
| IN | Vectren Energy Delivery (Indiana Gas and Southern Indiana Gas & Electric) | Gas | Compliance and System Improvement Adjustment | System and pressure improvements, storage operations, instrumentation and communications equipment, public improvement projects, service replacements, and economic development | Cause 44429 (August 2014) |
| KS | Atmos Energy | Gas | Gas System Reliability Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket 10-ATMG-133-TAR (December 2009) |
| KS | Black Hills Energy (Aquila) | Gas | Gas System Reliability Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket 08-AQLG-852-TAR (July 2008) |
| KS | Kansas Gas Service | Gas | Gas System Reliability Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket 10-KGSG-155-TAR (December 2009) |
| KS | Midwest Energy | Gas | Gas System Reliability Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket 09-MDWE-722-TAR (May 2009) |
| KY | Atmos Energy | Gas | Pipe Replacement Program Rider | Replacement of bare steel service lines, curb valves, meter loops, and mandated relocations | Docket 2009-00354 (May 2010) |
| KY | Columbia Gas | Gas | Advanced Main Replacement Rider | Replacement of cast iron and bare steel mains and services | Docket 2009-00141 (September 2009) |
| KY | Delta Natural Gas | Gas | Pipe Replacement Program Surcharge | Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations | Case 2010-00116 (October 2010) |
| KY | Kentucky Power | Electric | Environmental Cost Recovery Surcharge | Miscellaneous environmental projects | Docket 2002-00169 (March 2003) |
| KY | Kentucky Utilities | Electric | Environmental Cost Recovery Surcharge | Miscellaneous environmental projects | Case 93-465 (July 1994) |
| KY | Louisville Gas & Electric | Electric | Environmental Cost Recovery Surcharge | Miscellaneous environmental projects | Case 94-332 (April 1995) |
| KY | Louisville Gas & Electric | Gas | Gas Line Tracker | Replacement and transfer of ownership of customer owned service risers | Case 2012-00222 (December 2012) |
| LA | Cleco Power | Electric | Infrastructure and Incremental Costs Recovery | Projects to be determined in subsequent filings to Commission | Docket U-30689 and U-32779 (October 2010 and June 2014) |
| LA | Entergy Gulf States Louisiana | Electric | Formula Rate Plan-3 | Acquisition of generating facility, new generating facility or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million | Docket U-32707 (December 2013) |
| LA | Entergy Louisiana | Electric | Formula Rate Plan 7 | Cost of Ninemile 6 natural gas generating facility; New generating facility, acquisition of a generating facility, or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million | Docket U-32708 and 31971 (January 2014 and April 2012) |
| MA | Bay State Gas | Gas | Targeted Infrastructure Recovery Factor | Replacement of bare steel mains and services | DPU 09-30 |
| MA | Bay State Gas | Gas | Gas System Enhancement Adjustment Factor | Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, service tie-ins, encroached pipe, and meters | DPU 14-134 |
| MA | Berkshire Gas | Gas | Gas System Enhancement Adjustment Factor | Replacement of non-cathodically protected steel, cast iron mains and associated services, encroached pipe, and meter sets composed of non-cathodically protected steel, cast iron or copper | DPU 14-131 |
| MA | Fitchburg Gas & Electric Light | Gas | Gas System Enhancement Adjustment Factor | Replacement of cast main and unprotected steel mains and services and encroached pipe | DPU 14-130 |

## Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| MA | Massachusetts Electric | Electric | Net CapEx Factor | Potentially all distribution investments | DPU 09-39 |
| MA | Massachusetts Electric | Electric | Solar Cost Adjustment Provision | Solar generation | DPU 09-38 |
| MA | Massachusetts Electric | Electric | Smart Grid Adjustment Provision | Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators | DPU 11-129 |
| MA | Nantucket Electric | Electric | Solar Cost Adjustment Provision | Solar generation | DPU 09-38 |
| MA | Nantucket Electric | Electric | Smart Grid Adjustment Provision | Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators | DPU 11-129 |
| MA | National Grid (Boston-Essex Gas and Colonial Gas | Gas | Targeted Infrastructure Recovery Factor | Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators | DPU 10-55 |
| MA | National Grid (Boston-Essex Gas and Colonial Gas | Gas | Gas System Enhancement Adjustment Factor | Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters | DPU 14-132 |
| MA | New England Gas | Gas | Targeted Infrastructure Recovery Factor | Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron | DPU 10-114 |
| MA | New England Gas | Gas | Gas System Enhancement Adjustment Factor | Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters | DPU 14-133 |
| MA | NSTAR Electric | Electric | Capital Projects Scheduling List | Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade | DTE 05-85 and DPU 10-70-B |
| MA | NSTAR Electric | Electric | Smart Grid Adjustment Factor | Smart grid pilot | DPU-09-33 |
| MA | Western Massachusetts Electric | Electric | Solar Program Cost Adjustment | Solar generation | DPU 09-05 |
| MD | Baltimore Gas & Electric | Electric | Electric Reliability Investment Surcharge | Upgrades to improve poorest performing feeders, selective undergrounding, expanded recloser development on 13kV and 34 kV lines, diverse routing of 34 kV supply circuits | Case 9326 (December 2013) |
| MD | Baltimore Gas & Electric | Gas | Strategic Infrastructure Development and Enhancement Program | Replacement of bare steel mains and services, cast iron mains, copper services, and pre-1982 plastic "Ski Bar" risers | Case 9331 (January 2014) |
| MD | Columbia Gas of Maryland | Gas | Strategic Infrastructure Development and Enhancement Program | Replacement of bare steel and cast iron mains and bare steel services | Case 9332 (August 2014) |
| MD | Delmarva Power & Light | Electric | Grid Resiliency Charge | Feeder hardening | Case 9317 (September 2013) |
| MD | Potomac Electric Power | Electric | Grid Resiliency Charge | Feeder hardening | Case 9311 (July 2013) |
| MD | Washington Gas Light | Gas | Strategic Infrastructure Development and Enhancement Program Rider | Replacement of bare and unprotected steel mains and services, targeted copper and pre-1975 plastic services, mechanically coupled pipe main and services, and cast iron mains | Case 9335 (May 2014) |
| ME | Central Maine Power | Electric | Customer Relationship Management & Billing Rate Adjustment | Customer relationship management & billing system replacement | Docket 2015-00040 (October 2015) |
| ME | Maine Water Company | Water | Water Infrastructure Charge | Replacement of stationary physical plant assets needed to operate a water system | Various orders separately issued for operating divisions |
| ME | Northern Utilities | Gas | Targeted Infrastructure Recovery Adjustment | Cast iron, bare steel, and unprotected coated steel mains and services replacements, replacement of farm tap regulators | Docket 2013-00133 (December 2013) |
| MI | Consumers Energy | Gas | Enhanced Infrastructure Replacement Program | Cast iron replacements | Case U-17643 (January 2015) |
| MI | Michigan Consolidated Gas (now DTE Gas) | Gas | Infrastructure Recovery Mechanism | Replacement of cast iron mains, replacement of indoor meters with outdoor meters, pipeline integrity projects designed to comply with federal and state safety standards | Case U-16999 (April 2013) |
| MI | SEMCO Gas | Gas | Main Replacement Rider | Replacement of cast iron and unprotected steel mains and service lines | Case U-16169 and U-17824 (January 2011 and June 2015) |
| MN | Interstate Power & Light | Electric | Renewable Energy Recovery Adjustment | Renewable generation | Docket M-10-312 (December 2013) |
| MN | Minnesota Power | Electric | Arrowhead Regional Emission Abatement Rider | Miscellaneous environmental projects | Docket M-05-1678 (June 2006) |
| MN | Minnesota Power | Electric | Transmission Cost Recovery Rider | Incremental transmission investment | Docket M-07-965 (December 2007) |
| MN | Minnesota Power | Electric | Renewable Resource Rider | Renewable generation | Docket M-10-273 (July 2010) |
| MN | Minnesota Power | Electric | Rider for Boswell Unit 4 Emission Reduction | Miscellaneous environmental projects | Docket M-12-920 (November 2013) |
| MN | Northern States Power (Xcel Energy) | Electric | Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider) | Miscellaneous environmental projects | Docket M-02-633 (March 2004) |
| MN | Northern States Power (Xcel Energy) | Electric | Transmission Cost Recovery Rider | Incremental transmission investment | Docket M-06-1103 (November 2006) |
| MN | Northern States Power (Xcel Energy) | Electric | Renewable Energy Standard Cost Recovery Rider | Renewable generation | M-07-872 (March 2008) |
| MN | Northern States Power (Xcel Energy) | Gas | State Energy Policy Rider | Cast iron replacements | Docket M-08-261 (November 2008) |
| MN | Northern States Power (Xcel Energy) | Electric | Mercury Cost Recovery Rider | Miscellaneous environmental projects | Docket M-09-847 (November 2009) |
| MN | Otter Tail Power | Electric | Renewable Resource Cost Recovery Rider | Renewable generation | Docket M-08-119 (August 2008) |
| MN | Otter Tail Power | Electric | Transmission Cost Recovery Rider | Incremental transmission investment | Docket M-09-881 (January 2010) |
| MO | AmerenUE | Gas | Infrastructure System Replacement Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Case GT-2008-0184 (February 2008) |
| MO | Atmos Energy | Gas | Infrastructure System Replacement Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket GO-2009-0046 (October 2008) |
| MO | Laclede Gas | Gas | Infrastructure System Replacement Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket GR-2007-0208 (July 2007) |
| MO | Missouri American Water | Water | Infrastructure System Replacement Surcharge | Replacement of mains, associated valves and hydrants, main cleaning and relining projects | Case WO-2004-0116 (December 2003) |
| MO | Missouri Gas Energy | Gas | Infrastructure System Replacement Surcharge | Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations | Docket GR-2009-0355 (February 2010) |

## Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| MS | Atmos Energy | Gas | Supplemental Growth Rider | Extraordinary service expansions to new industrial customers for economic development | Docket 2013-UN-23 (July 2013) |
| MS | Centerpoint Energy | Gas | Supplemental Growth Rider | Extraordinary service expansions to new commercial and industrial customers for economic development | Docket 13-UN-214 (October 2013) |
| MS | Mississippi Power | Electric | Enviromental Compliance Overview Plan Rate | Miscellaneous environmental projects | Docket 92-UA-0058 and 92-UN-0059 (July 1992) |
| MT | Northwestern Energy | Electric | NA - Amounts recovered through electric supply service rates | Generation | Docket D.2008.6.69 (November 2008) |
| MT | Northwestern Energy | Gas | Natural Gas Supply Tracker | Battle Creek natural gas production resources | Docket D2012.3.25 (November 2012) |
| NC | Aqua North Carolina | Water | Water System Improvement Charge | Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways | Docket W-218, Sub 363 (May 2014) |
| NC | Aqua North Carolina | Water | Sewer System Improvement Charge | Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations | Docket W-218, Sub 363 (May 2014) |
| NC | Carolina Water Service | Water | Water System Improvement Charge | Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways | Docket W-354, Sub 336 (March 2014) |
| NC | Carolina Water Service | Water | Sewer System Improvement Charge | Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations | Docket W-354, Sub 336 (March 2014) |
| NC | Piedmont Natural Gas | Gas | Integrity Management Rider | Investments driven by federal pipeline safety and integrity requirements | Docket G-9, Sub 631 (December 2013) |
| ND | Montana-Dakota Utilities | Electric | Environmental Cost Recovery Tariff | Miscellaneous environmental projects | Case PU-13-85 (December 2013) |
| ND | Montana-Dakota Utilities | Electric | Generation Resource Recovery Rider Tariff | New Generation | Case PU-14-108 (August 2014) |
| ND | Northern States Power- MN | Electric | Transmission Cost Rider | Transmission projects | Case PU-12-813 (February 2014) |
| ND | Northern States Power- MN | Electric | Renewable Energy Rider | North Dakota based renewable generation | Case PU-12-813 (February 2014) |
| ND | Otter Tail Power | Electric | Renewable Resource Rider | Renewables | Case PU-06-466 (May 2008) |
| ND | Otter Tail Power | Electric | Transmission Facility Cost Recovery Tariff | Transmission investments required to serve retail customers | Case PU-11-682 (April 2012) |
| ND | Otter Tail Power | Electric | Environmental Cost Recovery Tariff | Miscellaneous environmental projects | Case PU-13-84 (December 2013) |
| NE | Black Hills Nebraska Gas Utility | Gas | Infrastructure System Replacement Recovery Charge | Non-revenue increasing projects to replace existing assets | Application NG-0074 |
| NE | SourceGas Distribution | Gas | Pipeline Replacement Charge | Projects entering service before May 2014 that are installed to comply with safety requirements as replacements for existing facilities, projects that will extend the useful life of existing assets or enhance pipeline integrity, facility relocations | Application NG-0072 (June 2013) |
| NE | SourceGas Distribution | Gas | System Safety and Integrity Rider | Projects entering service after April 2014 that comply with federal regulations including transmission and distribution integrity management plans or are facility relocations costing $20,000 or more | Application NG-0078 (October 2014) |
| NH | Aquarion Water of New Hampshire | Water | Water Infrastructure and Conservation Adjustment Charge | Projects to upgrade or replace non-revenue producing assets including main, valve, and hydrant replacement, main cleaning and relining, and non-reimbursable relocations | Docket DW 08-098 (September 2009) |
| NH | Energy North | Gas | Cast Iron/Bare Steel Replacement Program | Replacement of cast iron and bare steel pipe | Docket DG-107 (June 2007) |
| NH | Granite State Electric | Electric | Reliability Enhancement Plan Capital Investment Allowance | Feeder hardening and asset replacement | Docket DG-107 (June 2007) |
| NH | Public Service Company of New Hampshire | Electric | Energy Service | Miscellaneous environmental projects | DE 11-250 (April 2012) |
| NH | Public Service Company of New Hampshire | Electric | Reliability Enhancement Plan | Reliability improvements | DE 09-035, DE 11-250, and DE 14-238 (June 2015) |
| NJ | Elizabethtown Gas | Gas | Elizabethtown Natural Gas Distribution Utility Reinforcement Effort | System hardening | Docket GO13090826 (July 2014) |
| NJ | New Jersey American Water | Water | Distribution System Improvement Charge | Incremental non-revenue water main replacement, rehabilitation, or mandated relocation projects, service line replacements, valve and hydrant replacement | Docket WR12070669 (October 2012) |
| NJ | New Jersey Natural Gas | Gas | New Jersey Reinvestment in System Enhancement | Storm hardening projects | Docket GR13090828 (July 2014) |
| NJ | Public Service Electric and Gas | Electric | Solar Generation Investment Program | Solar generation | Docket EO09020125 (August 2009) |
| NJ | Public Service Electric and Gas | Electric & Gas | Capital Infrastructure Investment Program | Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services | Dockets GO09010050, EO11020088, GO10110862 (April 2009 and July 2011) |
| NJ | Public Service Electric and Gas | Electric & Gas | Energy Strong Adjustment Mechanism | Electric: substation flood mitigation, gird reconfiguration strategies, and smart grid; Gas: Metering and regulating station flood mitigation, replacement of utilization pressure cast iron in flood prone areas | Docket EO13020155, GO13020156 (May 2014) |
| NJ | South Jersey Gas | Gas | Storm Hardening and Reliability Program | Replacement of low pressure mains and services with high pressure mains and services, removal of regulator stations, installation of excess flow valves in coastal areas | Docket GO13090814 (August 2014) |
| NJ | United Water New Jersey | Water | Distribution System Improvement Charge | Repair, replace, and/or clean mains, replace valves, hydrants, and service lines | Docket WR12080724 (October 2012) |
| NV | Southwest Gas | Gas | Gas Infrastructure Replacement Mechanism | Early vintage pipe replacements, conversion of master metered customers to individual meters | Docket 14-10002 (December 2014) |

## Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| NY | Corning Natural Gas | Gas | Safety and Reliability Charge | Replacement of leak prone pipe and ancillary costs to maintain a safe and reliable system | Case 11-G-0280 (October 2015) |
| NY | Keyspan Energy Long Island | Gas | Leak Prone Pipe Surcharge | Accelerated leak prone pipe removal program | Case 12-G-0214 (December 2014 and March 2015) |
| NY | Long Island American Water | Water | System Improvement Charge | Iron removal, storage tank rehabilitiation, suction well rehabilitation at selected plants, customer information system | Case 11-W-0200 (March 2012) |
| NY | United Water New Rochelle | Water | Long Term Main Renewal Project | Cleaning and relining of mains | Case 99-W-0948 (August 2000) |
| NY | United Water New York | Water | Underground Infrastructure Renewal Program | Replacement of infrastructure including mains, valves, services, meters, and hydrants | Case 06-W-0131 (December 2006) |
| NY | United Water New York | Water | New Water Supply Source Surcharge | Projects to provide new sources of water in the short and long term | Case 06-W-0131 (December 2006) |
| OH | Aqua Ohio | Water | System Infrastructure Improvement Surcharge | Replacement of service lines, mains, hydrants, valves, main extensions to resolve documented water supply problems | Case 04-1824-WW-SIC (March 2005) |
| OH | Cleveland Electric Illuminating | Electric | Rider AMI | Ohio Site Deployment | Cases 09-1820-EL-ATA and 12-1230-EL-SSO |
| OH | Cleveland Electric Illuminating | Electric | Delivery Capital Recovery Rider | Distribution, subtransmission, general, and intangible plant not included in most recent rate case | Case 10-388-EL-SSO (August 2010) |
| OH | Columbia Gas | Gas | Infrastructure Replacement Program Rider | Replacement of cast iron and bare steel mains & services, AMI | Cases 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case 09-1036-GA-RDR (April 2010) |
| OH | Duke Energy Ohio | Gas | Accelerated Main Replacement Program Rider | Replacement of bare steel and cast iron mains and services and faulty risers | 1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008) |
| OH | Duke Energy Ohio | Gas | Advanced Utility Rider | Gas AMI | Cases 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008) |
| OH | Duke Energy Ohio | Electric | Infrastructure Modernization Distribution Rider | Electric AMI | Cases 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008) |
| OH | Duke Energy Ohio | Electric | Distribution Capital Investment Rider | Distribution capital investments not recovered through other trackers | Case 14-841-EL-SSO (April 2015) |
| OH | East Ohio Gas d/b/a Dominion East Ohio | Gas | Pipeline Infrastructure Replacement Rider | Bare steel and cast iron pipelines & faulty riser replacements | Case 08-169-GA-ALT (October 2008) |
| OH | East Ohio Gas d/b/a Dominion East Ohio | Gas | Automated Meter Reading Charge | AMR | Cases 07-0829-GA-AIR and 06-1453-GA-UNC (October 2008); Case 09-38-GA-UNC (May 2009); Case 09-1875-GA-RDR (May 2010) |
| OH | Ohio American Water | Water | System Improvement Charge | Non-revenue producing service lines, hydrants, mains, valves, main extensions that improve supply problems, main cleaning | Case 05-577-WW-SIC (August 2005) |
| OH | Ohio Edison | Electric | Rider AMI | Ohio Site Deployment | Cases 09-1820-EL-ATA and 12-1230-EL-SSO |
| OH | Ohio Edison | Electric | Delivery Capital Recovery Rider | Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007) | Case 10-388-EL-SSO (August 2010) |
| OH | Ohio Power | Electric | Distribution Investment Rider | Net distribution capital additions since the date certain of most recent rate case not recovered through other riders | Case 11-346-EL-SSO |
| OH | Ohio Power | Electric | GridSMART Rider (Phase I) | Smart grid | Case 08-917-EL-SSO and 08-918-EL-SSO (March 2009) |
| OH | Toledo Edison | Electric | Rider AMI | Ohio Site Deployment | Cases 09-1820-EL-ATA and 12-1230-EL-SSO |
| OH | Toledo Edison | Electric | Delivery Capital Recovery Rider | Power distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007) | Case 10-388-EL-SSO (August 2010) |
| OH | Vectren Energy Delivery | Gas | Distribution Replacement Rider | Replacement of cast iron and bare steel mains and services | Cases 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009) |
| OK | Oklahoma Gas & Electric | Electric | System Hardening Recovery Rider | Undergrounding and other circuit hardening | Cause PUD 20080387, Order 567670 (May 2009) |
| OK | Oklahoma Gas & Electric | Electric | Smart Grid Rider | Smart grid | Cause PUD 201000029 (July 2010) |
| OK | Oklahoma Gas & Electric | Electric | Crossroads Rider | Crossroads Wind Farm | Cause PUD 201000037 (July 2010) |
| OK | Public Service Company of Oklahoma | Electric | System Reliability Rider | Grid resiliency projects | Cause PUD 201300202 (January 2014) |
| OK | Public Service Company of Oklahoma | Electric | Advanced Metering Infrastructure Tariff | Advanced metering infrastructure deployment | Cause PUD 201300217 (April 2015) |
| OR | Northwest Natural Gas | Gas | System Integrity Program | Bare steel replacement, transmission integrity management program, distribution integrity management program | Docket UM 1406, Order 09-067 (March 2009) |
| OR | PacifiCorp | Electric | Renewable Adjustment Clause | Renewable generation | Docket UM 1330 (December 2007) |
| OR | PacifiCorp | Electric | Lake Side 2 Tariff Rider | Generation | Docket UE 263, Order 13-474 (December 2013) |
| OR | PacifiCorp | Electric | M2O Transmission Rider | Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013 | Docket UE 246, Orders 12-493 and 13-195 (December 2012 and May 2013) |
| OR | Portland General Electric | Electric | Renewable Adjustment Clause | Renewable generation | Docket UM 1330 (December 2007) |
| PA | Columbia Gas | Gas | Distribution System Improvement Charge | Replacement of cast iron, bare steel, and first generation plastic mains and services, install excess flow valves, install or relocate automated meters, and replace risers, meter bars, and service regulators | P-2012-2338282 (March 2013) |
| PA | Columbia Water Company | Water | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-00021979 |
| PA | Duquesne Light | Electric | Smart Meter Charge Rider | AMI | Docket M-2009-2123948 (April 2010) |
| PA | Equitable Gas | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2013-2342745 (July 2013) |
| PA | Metropolitan Edison | Electric | Smart Meters Technologies Charge | AMI | Docket M-2009-2123950 (April 2010) |

# Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| PA | PECO | Electric | Smart Meter Cost Recovery Rider | AMI | Docket M-2009-2123944 (April 2010) |
| PA | PECO | Electric | Distribution System Improvement Charge | Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations | Docket P-2015-2471423 (October 2015) |
| PA | PECO | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2013-2347340 (September 2015) |
| PA | Pennsylvania Electric | Electric | Smart Meters Technologies Charge | AMI | Docket M-2009-2123950 (April 2010) |
| PA | Pennsylvania Power | Electric | Smart Meters Technologies Charge | AMI | Docket M-2009-2123950 (April 2010) |
| PA | Pennsylvania-American Water | Water | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-000961031 (August 1996) |
| PA | Peoples Natural Gas | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2013-2344596 (May 2013) |
| PA | Peoples TWP | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2013-2344595 (May 2013) |
| PA | Philadelphia Gas Works | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2012-2337737 (April 2013) |
| PA | Philadelphia Surburban Water | Water | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-00961035 (August 1996) |
| PA | PPL Electric Utilities | Electric | Act 129 Compliance Rider | AMI | Docket M-2009-2123945 (January 2010) |
| PA | PPL Electric Utilities | Electric | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., poles, wires) | Docket P-2012-2325034 (May 2013) |
| PA | UGI Central Penn Gas | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2013-2398835 (September 2014) |
| PA | UGI Penn Natural Gas | Gas | Distribution System Improvement Charge | Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services) | Docket P-2013-2397056 (September 2014) |
| PA | West Penn Power | Electric | Smart Meter Surcharge | AMI | Docket M-2009-2123951 (June 2011) |
| RI | Narragansett Electric (electric operations) | Electric | Electric Infrastructure, Safety, and Reliability Plan Factor | Replacements and load growth | Docket 4218 (December 2011) |
| RI | Narragansett Electric (gas operations) | Gas | Gas Infrastructure, Safety, and Reliability Plan Factor | Previous accelerated capital replacement program investments plus main and service replacements and reliability investments | Docket 4219 (September 2011) |
| SC | South Carolina Electric & Gas | Electric | NA | Nuclear generation | Docket 2008-196-E (March 2009) |
| SD | Black Hills Power | Electric | Environmental Improvement Adjustment tariff | Miscellaneous environmental projects | Docket EL11-001 |
| SD | Black Hills Power | Electric | Phase in plan rate | Gas-fired generation | Docket EL12-062 (September 2013) |
| SD | Northern States Power- MN | Electric | Environmental Cost Recovery Tariff | Miscellaneous environmental projects | Docket EL07-026 (January 2009) |
| SD | Northern States Power- MN | Electric | Transmission Cost Recovery Tariff | Transmission | Docket EL07-007 (January 2009) |
| SD | Northern States Power- MN | Electric | Infrastructure Rider | Generation | Docket EL 12-046 (April 2013) |
| SD | Otter Tail Power | Electric | Transmission Cost Recovery Tariff | Retail sales portion of specific transmission projects | Docket EL 10-015 (November 2011) |
| SD | Otter Tail Power | Electric | Environmental Quality Cost Recovery Tariff | Miscellaneous environmental projects | Docket EL 14-082 (December 2014) |
| TN | Piedmont Natural Gas | Gas | Integrity Management Rider | Distribution and transmission integrity management planning as required by the US Department of Transportation | Docket 13-00118 (May 2014) |
| TX | AEP Texas Central | Electric | Advanced Metering System Surcharge | AMI | Docket 36928 |
| TX | AEP Texas North | Electric | Advanced Metering System Surcharge | AMI | Docket 36928 |
| TX | Atmos Energy Mid Tex | Gas | Gas Reliability Infrastructure Program | Incremental investment in new and replacement pipe, pipeline integrity including mains replacement | Texas Utilities Code 104.301 and Gas Utilities Docket 9615 |
| TX | Atmos Energy Pipelines | Gas | Gas Reliability Infrastructure Program | Incremental investment in new and replacement pipe, pipeline integrity including mains replacement | Gas Utilities Dockets 9615 and 10640 |
| TX | Atmos Energy West Texas Division | Gas | Gas Reliability Infrastructure Program | Incremental investment in new and replacement pipe, pipeline integrity including mains replacement | Texas Utilities Code 104.301 and Gas Utilities Docket 9608 |
| TX | Centerpoint Energy Entex - Houston Division | Gas | Gas Reliability Infrastructure Program | Incremental investment in new and replacement pipe, pipeline integrity including mains replacement | Texas Utilities Code 104.301 and Gas Utilities Docket 10067 |
| TX | Centerpoint Energy Houston Electric | Electric | Advanced Metering System Surcharge | AMI | Docket 35620 (August 2008) |
| TX | Centerpoint Energy Houston Electric | Electric | Distribution Cost Recovery Factor | Change in net distribution rate base since last rate case | Docket 44572 (August 2015) |
| TX | Oncor Electric Delivery | Electric | Advanced Metering System Surcharge | AMI | Docket 35718 (August 2008) |
| TX | Texas-New Mexico Power | Electric | Advanced Metering System Surcharge | AMI | Docket 38306 (July 2011) |
| UT | Questar Gas | Gas | Infrastructure Rate Adjustment Tracker | Replacement of aging high-pressure feeder lines | Docket 09-057-16 (June 2010) |
| VA | Appalachian Power | Electric | Environmental & Reliability Cost Recovery Surcharge | Miscellaneous environmental & reliability projects | Docket PUE-2007-00069 (December 2007) |
| VA | Appalachian Power | Electric | Environmental Rate Adjustment Clause | Miscellaneous environmental projects | Case PUE-2011-00035 (November 2011) |
| VA | Appalachian Power | Electric | Generation Rate Adjustment Clause | Dresden plant | Docket PUE-2011-00036 (January 2012) |
| VA | Atmos Energy | Gas | Infrastructure Reliability and Replacement Adjustment | Replacement of first generation plastic pipe and service lines and bare steel mains and services | Case PUE-2012-00049 (August 2012) |
| VA | Columbia Gas of Virginia | Gas | SAVE Rider | Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure | Case PUE-2011-00049 (November 2011) |
| VA | Roanoke Gas Company | Gas | SAVE Rider | Replacement of cast iron mains, bare steel mains and services and pre-1973 plastic pipe | Case PUE-2012-00030 (August 2012) |
| VA | Virginia Electric Power | Electric | Rider S | Virginia City Hybrid Energy Center | Case PUE-2007-00066 (March 2008) |
| VA | Virginia Electric Power | Electric | Rider R | Bear Garden Generating Station | Case PUE-2009-00017 (March 2010) |
| VA | Virginia Electric Power | Electric | Rider W | Warren County Power Station | Case PUE-2011-00042 (February 2012) |
| VA | Virginia Electric Power | Electric | Rider B | Biomass conversions | Case PUE-2011-00073 (March 2012) |
| VA | Virginia Electric Power | Electric | Rider BW | Brunswick County Power Station (natural gas combined cycle generating station) | Case PUE-2012-00128 (August 2013) |

# Table 2 continued

| Jurisdiction | Company Name | Services Included | Tracker Name | Eligible Investments | Case Reference |
|---|---|---|---|---|---|
| VA | Virginia Natural Gas | Gas | SAVE Rider | Replacement of first generation plastic mains, cast and wrought iron mains, bare and ineffectively coated steel mains, and service lines installed prior to 1971 | Case PUE-2012-00012 (June 2012) |
| VA | Washington Gas Light | Gas | SAVE Rider | Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and pre-1975 plastic services | Cases PUE-2010-00087 and PUE-2012-00096 (April 2011 and November 2012) |
| WA | Cascade Natural Gas | Gas | Pipeline Replacement Program Cost Recovery Mechanism | Replacement of bare steel and poorly coated pipelines and distribution systems | Docket PG-131838 (October 2013) |
| WV | Appalachian Power | Electric | Construction/765kW Surcharge | Generation, environmental | Case 11-0274-E-GI (June 2011) |
| WV | Monongahela Power | Electric | Vegetation Management Surcharge | Capitalized distribution vegetation management expenses | Case 14-0702-E-42T (February 2015) |
| WV | Potomac Edison | Electric | Vegetation Management Surcharge | Capitalized distribution vegetation management expenses | Case 14-0702-E-42T (February 2015) |
| WV | Wheeling Power | Electric | Construction/765kW Surcharge | Generation, environmental | Case 11-0274-E-GI (June 2011) |
| WY | Black Hills Power | Electric | Cheyenne Prairie Generating Station rate rider tariff | Construction of Cheyenne Prairie Generating Station | Docket 20002-84-ET-12 (November 2012) |
| WY | Cheyenne Light, Fuel, & Power | Electric | Cheyenne Prairie Generating Station rate rider tariff | Construction of Cheyenne Prairie Generating Station | Docket 20003-123-ET-12 (November 2012) |

# III. Relaxing the Link Between Revenue and System Use

Policymakers are increasingly interested in relaxing the link between the revenues utilities realize, and the kWh and kW of system use by customers. This reduces the financial attrition that results from slowing growth in system use (given legacy rate designs) more efficiently than frequent rate cases. In addition, utilities have more incentive to embrace DSM. Three approaches to relaxing the revenue/usage link are well established: lost revenue adjustment mechanisms ("LRAMs"), revenue decoupling, and fixed/variable pricing.

## A. Lost Revenue Adjustment Mechanisms

LRAMs keep utilities whole for short-term losses in base rate revenues that are due to their DSM programs (and potentially also DG). Recovery usually is effected through a special rate rider. Estimates of load losses are needed.

LRAMs encourage utilities to embrace DSM that is eligible for LRAM treatment. They do not provide recovery for the revenue impact of external forces, like DSM programs managed by independent agencies, which slow load growth. Estimates of load savings from utility DSM can be complex and are sometimes controversial. The scope of DSM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. When usage charges are high, the utility remains at risk for revenue fluctuations in volumes and peak load due to weather, local economic activity, and other volatile demand drivers.

Precedents for LRAMs are detailed in Table 3 and Figure 4 below.[3] LRAMs are currently the most popular means of relaxing the link between revenue and system use in the US electric utility industry. Since our 2013 survey, LRAMs have been adopted for electric utilities in Arizona, Louisiana, and Mississippi. A few utilities have LRAMs that address DG. LRAMs are less popular for gas distributors since the declining average use they have typically experienced for many years is due chiefly to external forces that LRAMs don't address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large load customers.

## B. Revenue Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its actual revenue track its allowed revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and adjusts rates to reduce them. The RAM escalates allowed revenue to provide relief for growing cost pressures.

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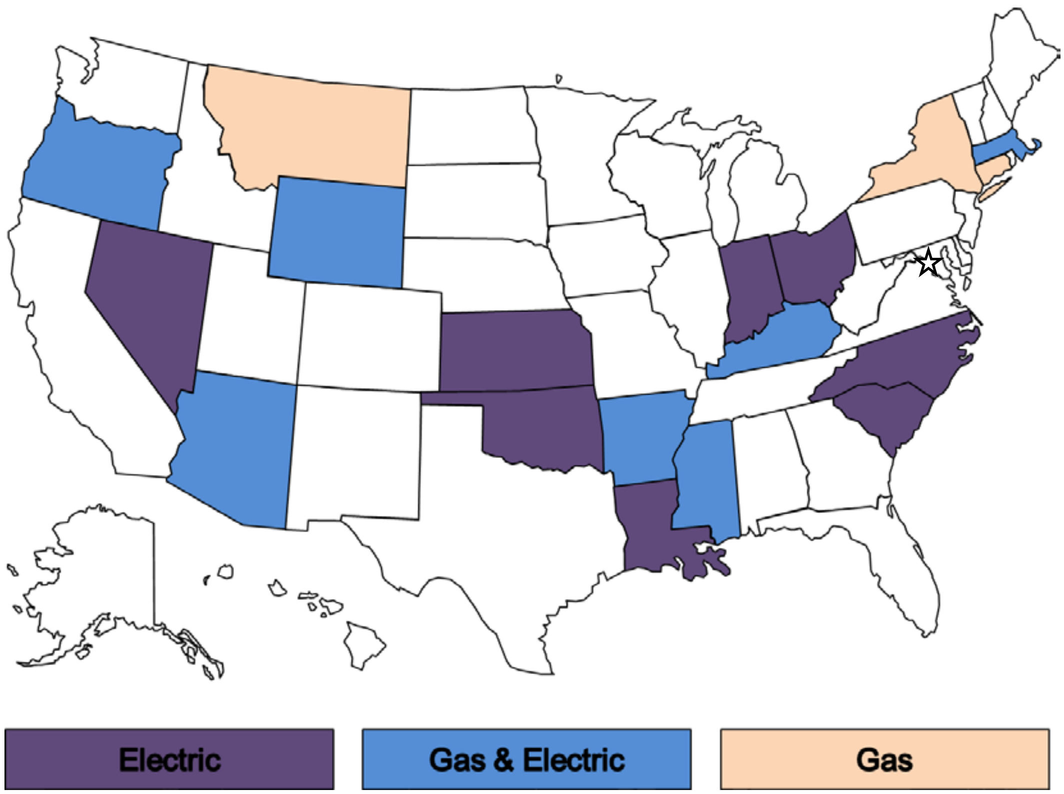
[3] Some mechanisms similar to LRAMs are excluded from this survey.

Figure 4: Current LRAMs by State




RDMs can make true ups annually or more frequently. More frequent adjustments cause actual revenue to track allowed revenue more closely so that rate adjustments are smaller. The size of the rate adjustment that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of DSM programs. RDMs also vary in terms of the services for which revenues are pooled for true up purposes. In some plans all services are placed in the same "basket." Other plans have multiple baskets, and these insulate customers of services in each basket from changes in revenue for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between allowed revenue and weather normalized actuals. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

Table 3

# Current LRAM Precedents[1]

| State | Company | Services | Approval Date | Case Reference |
|---|---|---|---|---|
| AR | Arkansas Oklahoma Gas | Gas | June 2011 | Docket 07-077-TF, Order Number 30 |
| AR | Centerpoint Energy Arkla | Gas | June 2011 | Docket 07-081-TF, Order Number 31 |
| AR | Entergy Arkansas | Electric | June 2011 | Docket 07-085-TF, Order Number 40 |
| AR | Oklahoma Gas & Electric | Electric | June 2011 | Docket 07-075-TF, Order 26 |
| AR | SourceGas Arkansas | Gas | June 2011 | Docket 07-078-TF, Order 26 |
| AR | Southwestern Electric Power | Electric | June 2011 | Docket 07-082-TF, Orders 35 and 36 |
| AZ | Arizona Public Service | Electric | May 2012 | Docket E-01345A-11-0224, Decision 73l83 |
| AZ | Tucson Electric Power | Electric | June 2013 | Docket E-01933A-12-0291; Decision 73912 |
| AZ | UNS Electric | Electric | September 2013 | Docket E-04204A-12-0504; Decision 74235 |
| AZ | UNS Gas | Gas | May 2012 | Docket G-04204A-11-0158 Decision 73142 |
| CT | Southern Connecticut Gas | Gas | August 1995 | Docket 93-03-09 |
| CT | Yankee Gas Service | Gas | January 2012 | Docket 11-10-03 |
| IN | Duke Energy Indiana (PSI) | Electric | February 2010 | Cause 43374 |
| IN | Indiana-Michigan Power | Electric | September 2010 | Cause 43827 |
| IN | Northern Indiana Public Service | Electric | May 2011 | Cause 43618 |
| IN | Southern Indiana Gas & Electric | Electric | August 2011 (large commercial and industrials), June 2012 (residential and small commercial) | Causes 43938 and 43405 DSMA 9 S1 |
| KS | Kansas Gas & Electric | Electric | January 2011 | Docket 10-WSEE-775-TAR |
| KS | Westar Energy | Electric | January 2011 | Docket 10-WSEE-775-TAR |
| KY | Atmos Energy | Gas | September 2009 | Case 2008-00499 |
| KY | Columbia Gas of Kentucky | Gas | October 2009 | Case 2009-00141 |
| KY | Delta Natural Gas | Gas | July 2008 | Docket 2008-00062 |
| KY | Duke Energy Kentucky | Electric | December 1995 and February 2005 | Cases 95-321 and 2004-00389 |
| KY | Duke Energy Kentucky | Gas | February 2005 | Case 2004-00389 |
| KY | Kentucky Power | Electric | December 1995 | Case 95-427 |
| KY | Kentucky Utilities | Electric | May 2001 | Case 2000-0459 |
| KY | Louisville Gas & Electric | Electric & Gas | November 1993 | Case 93-150 |
| LA | Cleco Power | Electric | October 2014 | Docket R-31106 |
| LA | Entergy Gulf States Louisiana | Electric | October 2014 | Docket R-31106 |
| LA | Entergy Louisiana | Electric | October 2014 | Docket R-31106 |
| LA | Southwestern Electric Power | Electric | October 2014 | Docket R-31106 |
| MA | All Electric distributors | Electric | July 2012 | D.P.U. 12-01A |
| MA | Berkshire Gas | Gas | October 1992 | D.P.U. 91-154 |
| MA | Commonwealth Gas d/b/a NSTAR Gas | Gas | November 1994 | D.P.U. 94-128 |

Table 3 (cont'd)

| State | Company | Services | Approval Date | Case Reference |
|---|---|---|---|---|
| MA | NSTAR Electric | Electric | April 1992, June 1994, and June 2010 | D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06 |
| MS | Atmos Energy | Gas | August 2014 | Docket 2014-UA-017 |
| MS | Centerpoint Energy | Gas | August 2014 | Docket 2014-UA-007 |
| MS | Entergy Mississippi | Electric | September 2014 | Docket 2009-UN-064 |
| MS | Mississippi Power | Electric | March 2015 | Docket 2014-UN-10 |
| MT | Montana-Dakota Utilities | Gas | October 2006 | Docket D2005.10.156; Order 6697c |
| NC | Duke Energy Carolinas | Electric | February 2010 | Docket E-7, Sub 831 |
| NC | Progress Energy Carolinas (Carolina Power & Light) | Electric | November 2009 | Docket E-2, Sub 931 |
| NC | Virginia Electric Power | Electric | October 2011 | Docket E-22, Sub 464 |
| NV | Nevada Energy | Electric | May 2011 | Docket 10-10024 |
| NV | Sierra Pacific Power | Electric | May 2011 | Docket 10-10025 |
| NY | Keyspan Long Island | Gas | December 2009 | Case 06-G-1186; Currently effective for all customers not in RDM |
| NY | Keyspan New York | Gas | December 2009 | Case 06-G-1185; Currently effective for all customers not in RDM |
| OH | American Electric Power (Ohio Power, Columbus Southern Power) | Electric | May 2010 | Docket 09-1089-EL-POR; Effective for classes not included in RDM |
| OH | Dayton Power & Light | Electric | June 2009 | Docket 08-1094-EL-SSO |
| OH | Duke Energy Ohio (Cincinnati Gas & Electric) | Electric | July 2007 and August 2012 | Dockets 06-0091-EL-UNC and 11-4393-EL-RDR; Effective for classes not included in RDM |
| OH | First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison) | Electric | March 2009 | Docket 08-935-EL-SSO |
| OK | Empire District Electric | Electric | November 2009 | Cause 200900146<br>Order 571326 |
| OK | Oklahoma Gas & Electric | Electric | July 2008 | Cause 200800059<br>Order 556179 |
| OK | Public Service of Oklahoma | Electric | January 2010 | Cause PUD 200900196; Order 572836 |
| OR | Cascade Natural Gas | Gas | April 2006 | Order 06-191; UG 167 Effective for classes not included in RDM |
| OR | Portland General Electric | Electric | September 2001 | Order 01-836; UE 79 Effective for classes not included in RDM |
| OR | Avista Utilities | Gas | December 1993 | Order 93-1881 |
| SC | Duke Energy Carolinas | Electric | January 2010 | Docket 2009-226-E<br>Order 2010-79 |
| SC | Progress Energy Carolinas | Electric | June 2009 | Docket 2008-251-E<br>Order 2009-373 |
| SC | South Carolina Electric & Gas | Electric | July 2010 | Docket 2009-261-E, Order 2010-472 |
| WY | Cheyenne Light, Fuel, and Power | Electric & Gas | September 2011 | Dockets 20003-108-EA-10 and 30005-140-GA-10 |
| WY | Montana-Dakota Utilities | Electric | January 2007 | Docket 20004-65-ET-06 |

[1] LRAMs listed here include only those mechanisms that compensate utilities for actual revenues lost due to DSM and DG.

The great majority of decoupling systems have a RAM since, if allowed revenue is static, the utility will experience financial attrition as its costs inevitably rise. Utilities that do not have RAMs in their decoupling systems often file frequent rate cases or are allowed to use capital cost trackers to address attrition. The more important issue in a proceeding to consider decoupling is therefore the design of the RAM rather than the need for one.

Most RAMs escalate allowed revenue only for customer growth. Escalation for customer growth is sensible because it is an important driver of cost and also highly correlated with other drivers such as peak demand. The need for rate cases is thereby reduced but is rarely eliminated since cost has other drivers such as input price inflation. When RAMs are escalated only for customer growth, utilities usually retain the freedom to file rate cases to address other cost factors and often do. Some RAMs are “broad-based” in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can materially reduce the need for rate cases and provide a foundation for a multiyear rate plan.

Revenue decoupling compensates utilities for declining average use even if it is driven in part by external forces such as independently administered DSM programs. The lost revenue disincentive is removed for a wide array of utility initiatives to encourage DSM without requiring load impact calculations or rate designs that discourage DSM. To the extent that recovery of allowed revenue is ensured, utilities can use rate designs with usage charges more aggressively to foster DSM. This makes environmental intervenors strong supporters of decoupling. Controversy over billing determinants in rate cases with future test years is reduced.

Revenue decoupling is a popular means of relaxing the link between a utility’s revenue and customers’ kWh consumption. States that have tried gas and electric revenue decoupling are indicated on the maps below in Figures 5a and 5b, respectively. Revenue decoupling precedents in the United States and Canada are detailed in Table 4. In the electric utility industry, decoupling has been favored in states that strongly support DSM. Since our 2013 survey, decoupling has been adopted for electric utilities in Connecticut, Maine, Minnesota, and Washington state. Decoupling is the most widespread means of relaxing the revenue/usage link for gas distributors. This reflects the fact that gas distributors often experience declining average use and that this has been driven chiefly by external forces. Table 4 indicates the kinds of RAMs chosen in approved decoupling systems. Note that RAMs for electric utilities are frequently broad-based.

## C. Fixed/Variable Pricing

Fixed/variable pricing is an approach to rate design that uses fixed charges (charges that do not vary with the actual sales volume or peak demand) to compensate utilities for fixed costs of service. For residential and small commercial services, customer charges (a flat monthly fee per customer) are the most common fixed charge used. Base revenue thus tends to grow at the gradual pace of customer growth. A *straight* fixed/variable (“SFV”) rate design recovers *all* base revenue through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed/variable pricing.

Figure 5a: Electric Revenue Decoupling by State

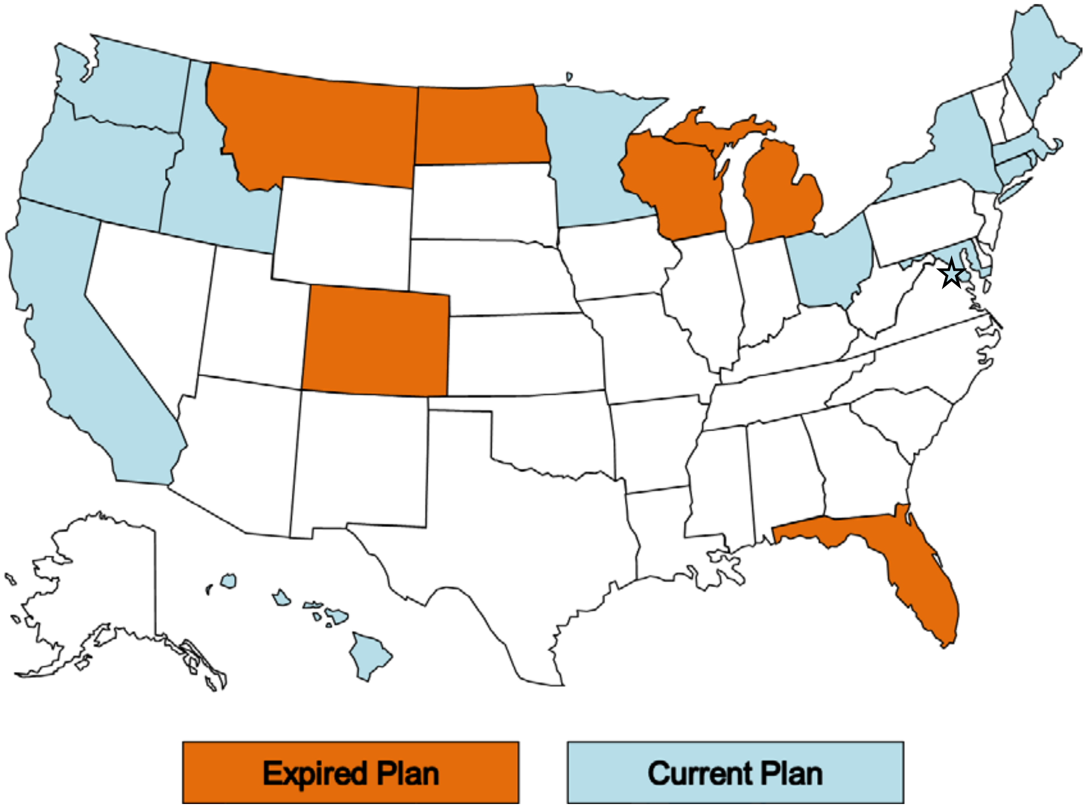



Figure 5b: Gas Revenue Decoupling by State

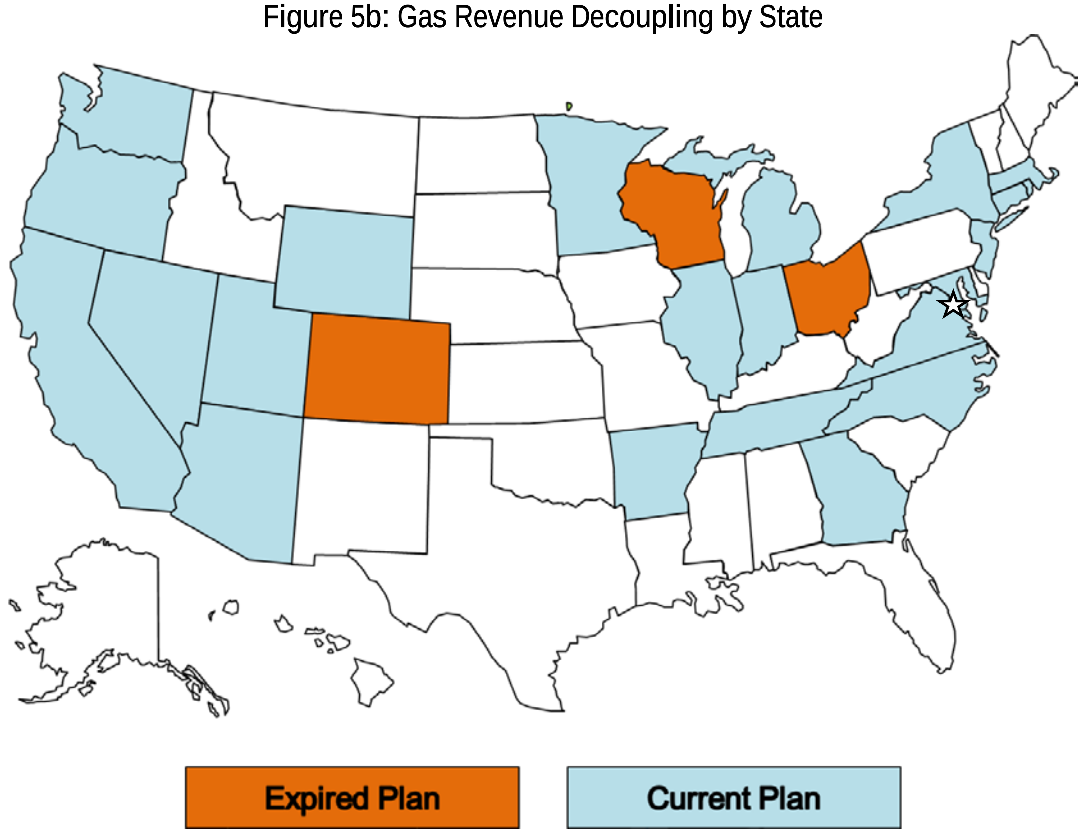


Table 4

# Revenue Decoupling Precedents

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| **Current** | | | | | |
| **United States** | | | | | |
| **AR** | Arkansas Oklahoma Gas | Gas | 2014-open | No RAM but multiple capital cost trackers | Docket 13-078-U |
| **AR** | CenterPoint Energy | Gas | 2008-2016 | No RAM but multiple capital cost trackers | Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF |
| **AR** | SourceGas Arkansas (Arkansas Western) | Gas | 2014-open | No RAM but multiple capital cost trackers | Docket 13-079-U |
| **AZ** | Southwest Gas | Gas | 2012-open | Customers | Docket G-01551A-10-0458 |
| **CA** | Bear Valley Electric Service | Electric | 2013-2016 | Stairstep | Decision 14-11-002 |
| **CA** | California Pacific Electric | Electric | 2013-2015 | Indexing | Decision 12-11-030 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 2014-2016 | Stairstep | Decision 14-08-032 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 2012-2015 | Stairstep | Decision 13-05-010 |
| **CA** | Southern California Edison | Electric | 2012-2014 | Hybrid | Decision 12-11-051 |
| **CA** | Southern California Gas | Gas | 2012-2015 | Stairstep | Decision 13-05-010 |
| **CA** | Southwest Gas | Gas | 2014-2018 | Stairstep | Decision 14-06-028 |
| **CT** | Connecticut Light & Power | Electric | 2014-open | No RAM | Docket 14-05-06 |
| **CT** | Connecticut Natural Gas | Gas | 2014-open | No RAM | Docket 13-06-08 |
| **CT** | United Illuminating | Electric | 2013-open | Stairstep until July 2015, No RAM thereafter | Docket 13-01-19 |
| **DC** | Potomac Electric Power | Electric | 2010-open | Customers | Order 15556 |
| **GA** | Atmos Energy | Gas | 2012-open | No RAM but FRP type mechanism also in effect | Docket 34734 |
| **HI** | Hawaiian Electric Company | Electric | 2011-open | Hybrid | Dockets 2008-0274, 2008-0083, 2013-0141 |
| **HI** | Hawaiian Electric Light Company | Electric | 2012-open | Hybrid | Dockets 2008-0274, 2009-0164, 2013-0141 |
| **HI** | Maui Electric | Electric | 2012-open | Hybrid | Dockets 2008-0274, 2009-0163, 2013-0141 |
| **ID** | Idaho Power | Electric | 2012-open | Customers | Cases IPC-E-11-19, IPC-E-14-17 |
| **IL** | North Shore Gas | Gas | 2012-open | No RAM | Case 11-0280 |
| **IL** | Peoples Gas Light & Coke | Gas | 2012-open | No RAM but broad-based capital cost tracker | Case 11-0281 |
| **IN** | Citizens Gas | Gas | 2007-open | Customers | Cause 42767 |
| **IN** | Indiana Gas | Gas | 2011-2015 | Customers | Cause 44019 |
| **IN** | Indiana Gas | Gas | 2016-2019 | Customers | Cause 44598 |
| **IN** | Indiana Natural Gas | Gas | 2014-open | Customers | Cause 44453 |
| **IN** | Vectren Southern Indiana | Gas | 2011-2015 | Customers | Cause 44019 |
| **IN** | Vectren Southern Indiana | Gas | 2016-2019 | Customers | Cause 44598 |
| **MA** | Bay State Gas | Gas | 2015-2018 | Revenue per Customer Stairstep | DPU 15-50 |
| **MA** | Boston-Essex Gas | Gas | 2010-open | Customers | DPU 10-55 |
| **MA** | Colonial Gas | Gas | 2010-open | Customers | DPU 10-55 |
| **MA** | Fitchburg Gas & Electric | Gas | 2011-open | Customers | DPU 11-02 |
| **MA** | Fitchburg Gas & Electric | Electric | 2011-open | No RAM | DPU 11-01 |
| **MA** | Massachusetts Electric | Electric | 2010-open | No RAM but broad-based capital cost tracker | DPU 09-39 |
| **MA** | New England Gas | Gas | 2011-open | Customers | DPU 10-114 |
| **MA** | Western Massachusetts Electric | Electric | 2011-open | No RAM | DPU 10-70 |
| **MD** | Baltimore Gas & Electric | Electric | 2008-open | Customers | Letter Orders ML 108069, 108061 |
| **MD** | Baltimore Gas & Electric | Gas | 1998-open | Customers | Case 8780 |
| **MD** | Chesapeake Utilities | Gas | 2006-open | Customers | Order 81054 |
| **MD** | Columbia Gas of Maryland | Gas | 2013-open | Customers | Order 85858 |
| **MD** | Delmarva Power & Light | Electric | 2007-open | Customers | Order 81518 |
| **MD** | Potomac Electric Power | Electric | 2007-open | Customers | Order 81517 |
| **MD** | Washington Gas Light | Gas | 2005-open | Customers | Order 80130 |
| **ME** | Central Maine Power | Electric | 2014-open | Customers | Docket 2013-00168 |

Table 4 (cont'd)

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| **Current** (cont'd) | | | | | |
| **United States** (cont'd) | | | | | |
| **MI** | Consumers Energy | Gas | 2015-open | No RAM | Case U-17643 |
| **MI** | Michigan Consolidated Gas | Gas | 2013-open | No RAM | Case U-16999 |
| **MI** | Michigan Gas Utilities | Gas | 2015-open | No RAM | Case U-17273 |
| **MN** | CenterPoint Energy | Gas | 2015-2018 | Customers | GR-13-316 |
| **MN** | Minnesota Energy Resources | Gas | 2013-2016 | Customers | GR-10-977 |
| **MN** | Northern States Power - MN | Electric | 2016-2018 | Customers | GR-13-868 |
| **NC** | Piedmont Natural Gas | Gas | 2008-open | Customers | Docket G-9, Sub 550 |
| **NC** | Public Service Co of NC | Gas | 2008-open | Customers | Docket G-5, Sub 495 |
| **NJ** | New Jersey Natural Gas | Gas | 2014-open | Customers | Docket GR13030185 |
| **NJ** | South Jersey Gas | Gas | 2014-open | Customers | Docket GR13030185 |
| **NV** | Southwest Gas | Gas | 2009-open | Customers | D-09-04003 |
| **NY** | Central Hudson G&E | Gas & Electric | 2015-2018 | Revenue per Customer Stairstep for Gas, Stairstep for Electric | Cases 14-E-0318, 14-G-0319 |
| **NY** | Consolidated Edison | Gas | 2014-2016 | Revenue per Customer Stairstep | Case 13-G-0031 |
| **NY** | Consolidated Edison | Electric | 2014-2016 | Stairstep | Case 13-E-0030 |
| **NY** | Corning Natural Gas | Gas | 2015-2017 | Customers | Case 11-G-0280 |
| **NY** | Keyspan Energy Delivery - Long Island | Gas | 2010-open | Revenue per Customer Stairstep through 2012, Customers After 2012 | Case 06-G-1186 |
| **NY** | Keyspan Energy Delivery New York | Gas | 2013-2014 | Revenue per Customer Stairstep through 2014, Customers After 2014 | Case 12-G-0544 |
| **NY** | National Fuel Gas | Gas | 2013-2015 | Customers | Case 13-G-0136 |
| **NY** | New York State Electric & Gas | Gas | 2010-2013 | Revenue per Customer Stairstep through 2013, Customers thereafter | Case 09-E-0715 |
| **NY** | New York State Electric & Gas | Electric | 2010-2013 | Stairstep through 2013, No RAM thereafter | Case 09-G-0716 |
| **NY** | Niagara Mohawk | Gas | 2013-2016 | Optional Revenue per Customer Stairstep | Case 12-G-0202 |
| **NY** | Niagara Mohawk | Electric | 2013-2016 | Optional Stairstep | Case 12-E-0201 |
| **NY** | Orange & Rockland Utilities | Gas | 2015-2018 | Revenue per Customer Stairstep | Case 14-G-0494 |
| **NY** | Orange & Rockland Utilities | Electric | 2015-2017 | Stairstep | Case 14-E-0493 |
| **NY** | Rochester Gas & Electric | Gas | 2010-2013 | Revenue per Customer Stairstep through 2013, Customers thereafter | Case 09-E-0717 |
| **NY** | Rochester Gas & Electric | Electric | 2010-2013 | Stairstep through 2013, No RAM thereafter | Case 09-G-0718 |
| **NY** | St. Lawrence Gas | Gas | 2010-open | Revenue per Customer Stairstep through 2012, Customers thereafter | Case 08-G-1392 |
| **OH** | AEP Ohio | Electric | 2012-2018 | Customers | Cases 11-351-EL-AIR, 13-2385-EL-SSO |
| **OH** | Duke Energy Ohio | Electric | 2015-open | Customers | Case 14-841-EL-SSO |
| **OR** | Cascade Natural Gas | Gas | 2013-2015 | Customers | Order 13-079 |
| **OR** | Northwest Natural Gas | Gas | 2012-open | Customers | Order 12-408 |
| **OR** | Portland General Electric | Electric | 2014-2016 | Customers | Order 13-459 |
| **RI** | Narragansett Electric | Electric | 2012-open | No RAM but broad-based capital cost tracker | Docket 4206 |
| **RI** | Narragansett Electric | Gas | 2012-open | Customers | Docket 4206 |
| **TN** | Chattanooga Gas | Gas | 2013-open | Customers | Docket 09-0183 |
| **UT** | Questar Gas | Gas | 2010-open | Customers | Docket 09-057-16 |
| **VA** | Columbia Gas of Virginia | Gas | 2013-2015 | Customers | Case PUE-2012-00013 |
| **VA** | Virginia Natural Gas | Gas | 2013-2016 | Customers | Case PUE-2012-00118 |
| **VA** | Washington Gas Light | Gas | 2013-2016 | Customers | Case PUE-2012-00138 |
| **WA** | Avista | Gas & Electric | 2015-2019 | Customers | Dockets UE-140188 and UG-140189 |
| **WA** | Puget Sound Energy | Gas & Electric | 2013-2016 | Revenue per Customer Stairstep | Dockets UE-121697 and UG-121705 |
| **WY** | Questar Gas | Gas | 2012-open | Customers | Docket 30010-113-GR-11 |
| **WY** | SourceGas Distribution | Gas | 2011-open | Customers | Docket 30022-148-GR-10 |

Table 4 (cont'd)

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| **Current** (cont'd) | | | | | |
| **Canada** | | | | | |
| **BC** | BC Hydro | Electric | 2015-2016 | Stairstep | Order G-48-14 |
| **BC** | FortisBC | Electric | 2014-2019 | Indexing | Order G-139-14 |
| **BC** | FortisBC Energy | Gas | 2014-2019 | Indexing | Order G-138-14 |
| **BC** | Pacific Northern Gas | Gas | 2003-open | Customers | N/A |
| **ON** | Enbridge Gas Distribution | Gas | 2014-2018 | Stairstep | EB-2012-0459 |
| **ON** | Union Gas | Gas | 2014-2018 | Indexing | EB-2013-0202 |
| **Historic** | | | | | |
| **United States** | | | | | |
| **AR** | Arkansas Oklahoma Gas | Gas | 2007-2013 | No RAM | Dockets 07-026-U, 07-077-TF |
| **AR** | Arkansas Western | Gas | 2008-2013 | No RAM | Docket 07-078-TF |
| **CA** | Bear Valley Electric Service | Electric | 2009-2012 | Stairstep | Decision 09-10-028 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 1982-1983 | Hybrid | Decision 93887 |
| **CA** | Pacific Gas & Electric | Electric | 1984-1985 | Hybrid | Decision 83-12-068 |
| **CA** | Pacific Gas & Electric | Electric | 1986-1989 | Hybrid | Decision 85-12-076 |
| **CA** | Pacific Gas & Electric | Electric | 1990-1992 | Hybrid | Decision 89-12-057 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 1993-1995 | Hybrid | Decision 92-12-057 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 2004-2006 | Indexing | Decision 04-05-055 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 2007-2010 | Stairstep | Decision 07-03-044 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 2011-2013 | Stairstep | Decision 11-05-018 |
| **CA** | Pacific Gas & Electric | Gas | 1978-1981 | No RAM | Decisions 89316, 91107 |
| **CA** | PacifiCorp | Electric | 1984-1985 | Stairstep | Decision 89-09-034 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 1982-1983 | Hybrid | Decision 93892 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 1986-1988 | Hybrid | Decision 85-12-108 |
| **CA** | San Diego Gas & Electric | Electric | 1989-1993 | Hybrid | Decision 89-11-068 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 1994-1999 | Hybrid | Decision 94-08-023 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 2005-2007 | Indexing | Decision 05-03-025 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 2008-2011 | Stairstep | Decision 08-07-046 |
| **CA** | Southern California Edison | Electric | 1983-1984 | Hybrid | Decision 82-12-055 |
| **CA** | Southern California Edison | Electric | 1986-1991 | Hybrid | Decision 85-12-076 |
| **CA** | Southern California Edison | Electric | 2001-2003 | Indexing | Decision 02-04-055 |
| **CA** | Southern California Edison | Electric | 2004-2006 | Hybrid | Decision 04-07-022 |
| **CA** | Southern California Edison | Electric | 2006-2008 | Hybrid | Decision 06-05-016 |
| **CA** | Southern California Edison | Electric | 2009-2011 | Stairstep | Decision 09-03-025 |
| **CA** | Southern California Gas | Gas | 1979-1980 | No RAM | Decision 89710 |
| **CA** | Southern California Gas | Gas | 1981-1982 | Stairstep | Decision 92497 |
| **CA** | Southern California Gas | Gas | 1983-1984 | Hybrid | Decision dated December 8, 1982 |
| **CA** | Southern California Gas | Gas | 1986-1989 | Hybrid | Decision 85-12-076 |
| **CA** | Southern California Gas | Gas | 1990-1993 | Hybrid | Decision 90-01-016 |
| **CA** | Southern California Gas | Gas | 1998-2002 | Indexing | Decision 97-07-054 |
| **CA** | Southern California Gas | Gas | 2005-2007 | Indexing | Decision 05-03-025 |
| **CA** | Southern California Gas | Gas | 2008-2011 | Stairstep | Decision 08-07-046 |
| **CA** | Southwest Gas | Gas | 2009-2013 | Stairstep | Decision 08-11-048 |
| **CO** | Public Service Company of Colorado | Gas | 2008-2011 | Customers | Decision C07-0568 |
| **CO** | Public Service Company of Colorado | Electric | 2012-2014 | Stairstep | Decision C12-0494 |
| **CT** | United Illuminating | Electric | 2009-2013 | Stairstep until 2011/No RAM for 2011 onwards | Docket 08-07-04 |
| **FL** | Florida Power Corporation | Electric | 1995-1997 | Customers | Docket 930444 |
| **ID** | Idaho Power | Electric | 2007-2009 | Customers | Case IPC-E-04-15 |
| **ID** | Idaho Power | Electric | 2010-2012 | Customers | Case IPC-E-09-28 |
| **IL** | North Shore Gas | Gas | 2008-2012 | Customers | Case 07-0241 |
| **IL** | Peoples Gas Light & Coke | Gas | 2008-2012 | Customers | Case 07-0242 |
| **IN** | Citizens Gas | Gas | 2007-2011 | Customers | Cause 42767 |
| **IN** | Vectren Energy | Gas | 2007-2011 | Customers | Cause 43046 |
| **IN** | Vectren Southern Indiana | Gas | 2007-2011 | Customers | Cause 43046 |
| **MA** | Bay State Gas | Gas | 2009-open | Customers | DPU 09-30 |
| **ME** | Central Maine Power | Electric | 1991-1993 | Customers | Docket 90-085 |
| **MI** | Consumers Energy | Electric | 2009-2011 | Customers | Case U-15645 |
| **MI** | Consumers Energy | Gas | 2010-2012 | Customers | Case U-15986 |
| **MI** | Detroit Edison | Electric | 2010-2011 | Customers | Case U-15768 |
| **MI** | Michigan Consolidated Gas | Gas | 2010-2012 | Customers | Case U-15985 |
| **MI** | Michigan Gas Utilities | Gas | 2010-2013 | Customers | Case U-15990 |
| **MI** | Upper Peninsula Power | Electric | 2010-2011 | Customers | Case U-15988 |
| **MN** | CenterPoint Energy | Gas | 2010-2013 | Customers | Docket GR-08-1075 |
| **MT** | Montana Power Company | Electric | 1994-1998 | Customers | Docket 93.6.24 |

Table 4 (cont'd)

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | |
| **United States** (cont'd) | | | | | |
| **NC** | Piedmont Natural Gas | Gas | 2005-2008 | Customers | Docket G-44 Sub 15 |
| **ND** | Northern States Power - MN | Electric | 2012 | Not Applicable, plan only 1 year in duration | Case PU-11-55 |
| **NJ** | New Jersey Natural Gas | Gas | 2007-2010 | Customers | Docket GR05121020 |
| **NJ** | New Jersey Natural Gas | Gas | 2010-2013 | Customers | Docket GR05121020 |
| **NJ** | South Jersey Gas | Gas | 2007-2010 | Customers | Docket GR05121019 |
| **NJ** | South Jersey Gas | Gas | 2010-2013 | Customers | Docket GR05121019 |
| **NY** | Central Hudson G&E | Gas | 2009-open | Customers | Case 08-E-0888 |
| **NY** | Central Hudson G&E | Electric | 2009 | No RAM | Case 08-E-0887 |
| **NY** | Central Hudson G&E | Gas & Electric | 2010-2013 | Revenue per Customer Stairstep for Gas, Stairstep for Electric | Case 09-E-0588 |
| **NY** | Central Hudson G&E | Gas & Electric | 2013-open | Customers for Gas, No RAM for Electric | Case 12-M-0192 |
| **NY** | Consolidated Edison | Electric | 1992-1995 | Stairstep | Opinion 92-8 |
| **NY** | Consolidated Edison | Gas | 2007-2010 | Stairstep | Case 06-G-1332 |
| **NY** | Consolidated Edison | Electric | 2008-open | No RAM | Case 07-E-0523 |
| **NY** | Consolidated Edison | Gas | 2010-2013 | Revenue per Customer Stairstep | Case 09-G-0795 |
| **NY** | Consolidated Edison | Electric | 2010-2013 | Stairstep | Case 09-E-0428 |
| **NY** | Corning Natural Gas | Gas | 2012-2015 | Revenue per Customer Stairstep | Case 11-G-0280 |
| **NY** | Keyspan Energy Delivery - New York | Gas | 2010-open | Revenue per Customer Stairstep | Case 06-G-1185 |
| **NY** | Long Island Lighting Company | Electric | 1992-1994 | Stairstep | Opinion 92-8 |
| **NY** | National Fuel Gas | Gas | 2008-open | Customers | Case 07-G-0141 |
| **NY** | New York State Electric & Gas | Electric | 1993-1995 | Stairstep | Opinion 93-22 |
| **NY** | Niagara Mohawk | Electric | 1990-1992 | Stairstep | Case 94-E-0098 |
| **NY** | Niagara Mohawk | Gas | 2009-open | Customers | Case 08-G-0609 |
| **NY** | Niagara Mohawk | Electric | 2011-open | No RAM | Case 10-E-0050 |
| **NY** | Orange & Rockland Utilities | Electric | 2012-2015 | Stairstep | Case 11-E-0408 |
| **NY** | Orange & Rockland Utilities | Electric | 2011-2012 | No RAM | Case 10-E-0362 |
| **NY** | Orange & Rockland Utilities | Electric | 2008-2011 | Stairstep | Case 07-E-0949 |
| **NY** | Orange & Rockland Utilities | Electric | 1991-1993 | Stairstep | Case 89-E-175 |
| **NY** | Orange & Rockland Utilities | Gas | 2012-2015 | Customers | Case 08-G-1398 |
| **NY** | Orange & Rockland Utilities | Gas | 2009-2012 | Revenue per Customer Stairstep | Case 08-G-1398 |
| **NY** | Rochester Gas & Electric | Electric | 1993-1996 | Stairstep | Opinion 93-19 |
| **OH** | Duke Energy Ohio | Electric | 2012-2014 | Customers | Case 11-5905-EL-RDR |
| **OH** | Vectren Energy | Gas | 2007-2009 | Customers | Case 05-1444-GA-UNC |
| **OR** | Cascade Natural Gas | Gas | 2007-2012 | Customers | Order 06-191 |
| **OR** | Northwest Natural Gas | Gas | 2002-2005 | Customers | Order 02-634 |
| **OR** | Northwest Natural Gas | Gas | 2005-2009 | Customers | Order 05-934 |
| **OR** | Northwest Natural Gas | Gas | 2009-2012 | Customers | Order 07-426 |
| **OR** | PacifiCorp | Electric | 1998-2001 | Indexing | Order 98-191 |
| **OR** | Portland General Electric | Electric | 1995-1996 | Stairstep | Order 95-0322 |
| **OR** | Portland General Electric | Electric | 2009-2010 | Customers | Order 09-020 |
| **OR** | Portland General Electric | Electric | 2011-2013 | Customers | Order 10-478 |
| **TN** | Chattanooga Gas | Gas | 2010-2013 | Customers | Docket 09-0183 |
| **UT** | Questar Gas | Gas | 2006-2010 | Customers | Docket 05-057-T01 |
| **VA** | Virginia Natural Gas | Gas | 2009-2012 | Customers | Case PUE-2008-00060 |
| **VA** | Washington Gas Light | Gas | 2010-2013 | Customers | Case PUE-2009-00064 |
| **WA** | Avista | Gas | 2007-2009 | Customers | Docket UG-060518 |
| **WA** | Avista | Gas | 2009-2012 | Customers | Docket UG-060518 |
| **WA** | Avista | Gas | 2013-2014 | Revenue per Customer Stairstep | Docket UG-120437 |
| **WA** | Cascade Natural Gas | Gas | 2005-2010 | Customers | Docket UG-060256 |
| **WA** | Puget Sound & Power | Electric | 1991-1995 | Customers | Docket UE-901184-P |
| **WI** | Wisconsin Public Service | Gas & Electric | 2009-2012 | Customers | D-6690-UR-119 |
| **WI** | Wisconsin Public Service | Gas & Electric | 2013 | Not Applicable, plan only 1 year in duration | Docket 6690-UR-121 |
| **WY** | Questar Gas | Gas | 2009-2012 | Customers | Docket 30010-94-GR-08 |

Table 4 (cont'd)

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | |
| **Canada** | | | | | |
| **BC** | BC Gas | Gas | 1994-1995 | Hybrid | Order G-59-94 |
| **BC** | BC Gas | Gas | 1996-1997 | Hybrid | N/A |
| **BC** | BC Gas | Gas | 1998-2000 | Hybrid | Order G-85-97 |
| **BC** | BC Gas | Gas | 2000-2001 | Hybrid | Order G-48-00 |
| **BC** | BC Hydro | Electric | 2009-2010 | Hybrid | Order G-16-09 |
| **BC** | BC Hydro | Electric | 2011 | Not Applicable, plan only 1 year in duration | Order G-180-10 |
| **BC** | BC Hydro | Electric | 2012-2014 | Stairstep | Order G-77-12A |
| **BC** | FortisBC | Electric | 2012-2013 | Stairstep | Order G 110-12 |
| **BC** | Terasen Gas | Gas | 2008-2009 | Hybrid | Order G-33-07 |
| **BC** | Terasen Gas | Gas | 2004-2007 | Hybrid | Order G-51-03 |
| **BC** | Terasen Gas | Gas | 2010-2011 | Hybrid | Order G-141-09 |
| **BC** | Terasen Gas | Gas | 2012-2013 | Stairstep | Order G-44-12 |
| **ON** | Enbridge Gas Distribution | Gas | 2008-2012 | Revenue per Customer Indexing | Docket EB-2007-0615 |
| **ON** | Union Gas | Gas | 2008-2012 | Indexing | Docket EB-2007-0606 |

Fixed/variable pricing relaxes the revenue/usage link with low administrative cost since it requires neither decoupling true ups nor load impact calculations. When average use is declining, base revenue will grow more rapidly with fixed/variable pricing so that rate cases tend to be less frequent even if the decline is largely driven by external forces. Base revenue grows more slowly than under conventional rate designs if average use is rising. The short term disincentive is removed to embrace various DSM initiatives. However, fixed/variable pricing reduces a utility's ability to use usage charges as a tool for promoting DSM. For example, it does not encourage customers with electric vehicles to charge these vehicles at night. Note also that the principle of rate design gradualism often discourages regulators from immediately adopting SFV pricing.

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed/variable pricing in retail ratemaking are listed below on Table 5 and Figure 6. It can be seen that fixed/variable pricing has to date been considerably more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced, and the fact that the decline has been driven largely by external forces. Since our 2013 survey, fixed/variable pricing has been implemented for an electric utility in Oklahoma.

In addition to the precedents listed here, utilities in Wisconsin and several other states have in recent years made sizable steps in the direction of fixed/variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than are utilities in the United States. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 6: Fixed/Variable Pricing Precedents by State

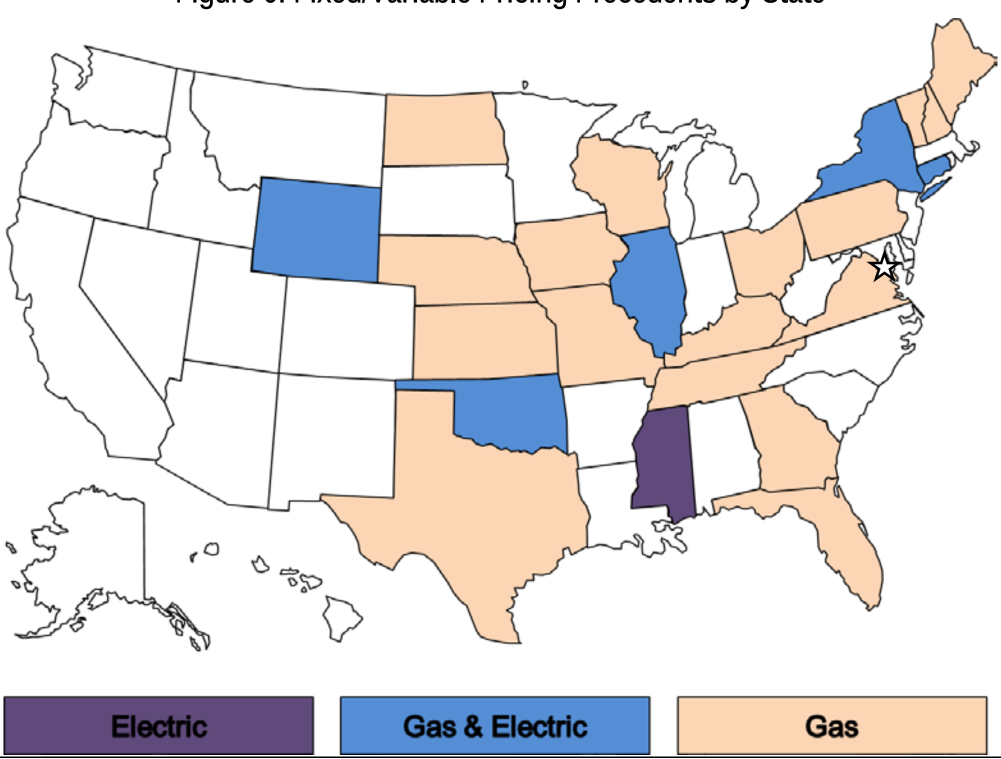


Table 5

# Fixed Variable Residential Pricing Precedents[1]

| Jurisdiction | Company Name | Services | Years in Place | Case Reference |
|---|---|---|---|---|
| **CT** | Connecticut Light & Power | Electric | 2007-open | Docket 07-07-01 |
| **CT** | Connecticut Natural Gas | Gas | 2014-open | Docket 13-06-08 |
| **CT** | United Illuminating | Electric | Occurred over period of years | No specific case |
| **CT** | Yankee Gas System | Gas | 2011-open | Docket 10-12-02 |
| **FL** | Peoples Gas System | Gas | 2009-open | Docket 080318-GU |
| **GA** | Liberty Utilities | Gas | 2015-open | Docket 34734 |
| **IA** | Black Hills Energy | Gas | 2009-open | Docket RPU-08-3 |
| **IL** | Ameren CILCO | Gas | 2008-2012 | Case 07-0588 |
| **IL** | Ameren CIPS | Gas | 2008-2012 | Case 07-0589 |
| **IL** | Ameren IP | Gas | 2008-2012 | Case 07-0590 |
| **IL** | Ameren Illinois | Gas | 2012-open | Case 11-0282 |
| **IL** | Ameren Illinois | Electric | Occurred over period of years | No specific case |
| **IL** | Commonwealth Edison | Electric | 2011-2013 | Case 10-0467 |
| **IL** | Mt. Carmel Public Utilities | Gas | 2013-open | Case 13-0079 |
| **IL** | North Shore Gas | Gas | 2008-open | Case 07-0241 |
| **IL** | Peoples Gas Light & Coke | Gas | 2008-open | Case 07-0242 |
| **KS** | Atmos Energy | Gas | 2010-open | Docket 10-ATMG-495-RTS |
| **KS** | Black Hills Energy (formerly Aquila) | Gas | 2007-open | Docket 07-AQLG-431-RTS |
| **KS** | Kansas Gas Service | Gas | 2012-open | Docket 12-KGSG-835-RTS |
| **KY** | Atmos Energy | Gas | 2014-open | Case 2013-00148 |
| **KY** | Columbia Gas | Gas | 2013-open | Case 2013-00167 |
| **KY** | Delta Natural Gas | Gas | 2007-open | Case 2007-00089 |
| **KY** | Duke Energy Kentucky | Gas | 2010-open | Case 2009-00202 |
| **ME** | Maine Natural Gas | Gas | Occurred over period of years | Docket 2009-00067 |
| **ME** | Northern Utilities | Gas | 2014-open | Docket 2013-00133 |
| **MO** | AmerenUE | Gas | 2007-open | Case GR-2007-0003 |
| **MO** | Atmos Energy | Gas | 2007-2010 | Case GR-2006-0387 |
| **MO** | Atmos Energy | Gas | 2010-open | Case GR-2010-0192 |
| **MO** | Empire District Gas | Gas | 2010-open | Case GR-2009-0434 |
| **MO** | Laclede Gas | Gas | 2002-open | Case GR-2002-356 |
| **MO** | Missouri Gas Energy | Gas | 2007-open | Case GR-2006-0422 |
| **MS** | Mississippi Power | Electric | Occurred over period of years | No specific case |
| **ND** | Xcel Energy | Gas | 2005-open | Case PU-04-578 |
| **NE** | SourceGas Distribution | Gas | 2012-open | Docket NG-0067 |
| **NH** | Liberty Utilities (EnergyNorth Natural Gas) | Gas | Occurred over period of years | No specific case |
| **NH** | Northern Utilities | Gas | 2014-open | DG 13-086 |
| **NY** | Central Hudson Gas & Electric | Electric & Gas | Occurred over period of years | No specific case |
| **NY** | Consolidated Edison | Electric & Gas | Occurred over period of years | No specific case |
| **NY** | Corning Gas | Gas | Occurred over period of years | No specific case |
| **NY** | Keyspan Energy Delivery - Long Island | Gas | Occurred over period of years | No specific case |
| **NY** | Keyspan Energy Delivery - New York | Gas | Occurred over period of years | No specific case |
| **NY** | National Fuel Gas | Gas | Occurred over period of years | No specific case |

## Table 5 (cont'd)

| Jurisdiction | Company Name | Services | Years in Place | Case Reference |
|---|---|---|---|---|
| **NY** | New York State Electric & Gas | Electric | Occurred over period of years | No specific case |
| **NY** | Niagara Mohawk | Electric & Gas | Occurred over period of years | No specific case |
| **NY** | Orange & Rockland | Electric & Gas | Occurred over period of years | No specific case |
| **NY** | Rochester Gas & Electric | Electric & Gas | Occurred over period of years | No specific case |
| **OH** | Columbia Gas | Gas | 2008-open | Case 08-0072-GA-AIR |
| **OH** | Dominion East Ohio | Gas | 2008-2010 | Case 07-830-GA-ALT |
| **OH** | Duke Energy Ohio (CG&E) | Gas | 2008-open | Case 07-590-GA-ALT |
| **OH** | Vectren Energy Delivery of Ohio | Gas | 2009-open | Case 07-1080-GA-AIR |
| **OK** | Arkansas Oklahoma Gas | Gas | 2013-open | Cause PUD 201200236 |
| **OK** | Centerpoint Energy | Gas | 2010-open | Cause PUD 201000030 |
| **OK** | Oklahoma Natural Gas | Gas | 2004-open | Causes PUD 200400610, PUD 201000048, PUD 200900110 |
| **OK** | Public Service Company of Oklahoma | Electric | 2015-open | Cause PUD 201300217 |
| **PA** | Columbia Gas | Gas | 2013-open | Docket R-2012-2321748 |
| **TN** | Atmos Energy | Gas | 2012-open | Docket 12-00064 |
| **TN** | Piedmont Natural Gas | Gas | 2012-open | Docket 11-00144 |
| **TX** | Atmos Energy - Mid-Tex Division | Gas | Occurred over period of years | No specific case |
| **TX** | Atmos Energy - West Texas Division | Gas | Occurred over period of years | No specific case |
| **TX** | Centerpoint Energy Houston Division | Gas | Occurred over period of years | No specific case |
| **TX** | Centerpoint Energy Beaumont/East Texas Division | Gas | Occurred over period of years | No specific case |
| **VA** | Columbia Gas of Virginia | Gas | Occurred over period of years | No specific case |
| **VT** | Vermont Gas Systems | Gas | Occurred over period of years | No specific case |
| **WI** | Madison Gas & Electric | Gas | 2015-open | Docket 3270-UR-120 |
| **WI** | Wisconsin Public Service | Gas | 2015-open | Docket 6690-UR-123 |
| **WY** | SourceGas Distribution | Gas | 2011-open | Docket 30022-148-GR-10 |
| **WY** | PacifiCorp (d/b/a Rocky Mountain Power) | Electric | 2009-open | Docket 20000-333-ER-08 |

[1] Fixed variable pricing precedents include power and gas distributors that have a customer charge equal to or in excess of $15 (or $20 for vertically integrated electric utilities).

# IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants (e.g., the residential delivery volume) are jointly considered in ratesetting. A historical test year ends before the rate case is filed. A forward (a/k/a "fully forecasted") test year ("FTY") begins after the rate case is filed. An FTY typically begins about the time the rate case is expected to end and new rates take effect. Two-year forecasts may be required in this event which span both the year of the rate case and the rate effective year.[4] In between forward and historical test years is the option of a "partially forecasted" test year in which some months of historical data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historical test years tend to be uncompensatory when cost is growing faster than billing determinants. Annual rate cases with historical test years can alleviate but not eliminate underearning under these conditions. The effect on credit metrics can be material.[5] Where historical test years are used, there are thus added advantages to implementing other Altreg innovations discussed in this survey.

Forward test years can fully compensate utilities when cost growth exceeds growth in billing determinants. If this imbalance is chronic, however, FTYs do not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, such as cost trackers or multiyear rate plans.

Many approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalize data for an historical reference period, adjusted for known and measurable changes, and then use indexing and other statistical methods to extend projections. A mixture of forecasting methods is common. For example, index-based forecasting may be used only for O&M expenses.

FTYs were adopted in many jurisdictions during the 1970s and 1980s, when rapid inflation and major plant additions coincided with oil shock-induced slowdowns in the growth of average use. Several additional states have recently moved in the direction of FTYs. Some of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized below in Figure 7 and Table 6. In many jurisdictions the use of partially or fully-forecasted test years is not standardized. For example, in some jurisdictions, including Illinois and North Dakota, utilities are allowed to select their type of rate case test year. Test year selection may also be made part of the rate case (e.g., Utah). A few jurisdictions allow forward test years to be used in rate cases or formula rate plans, but not both (e.g., Illinois and Arkansas).

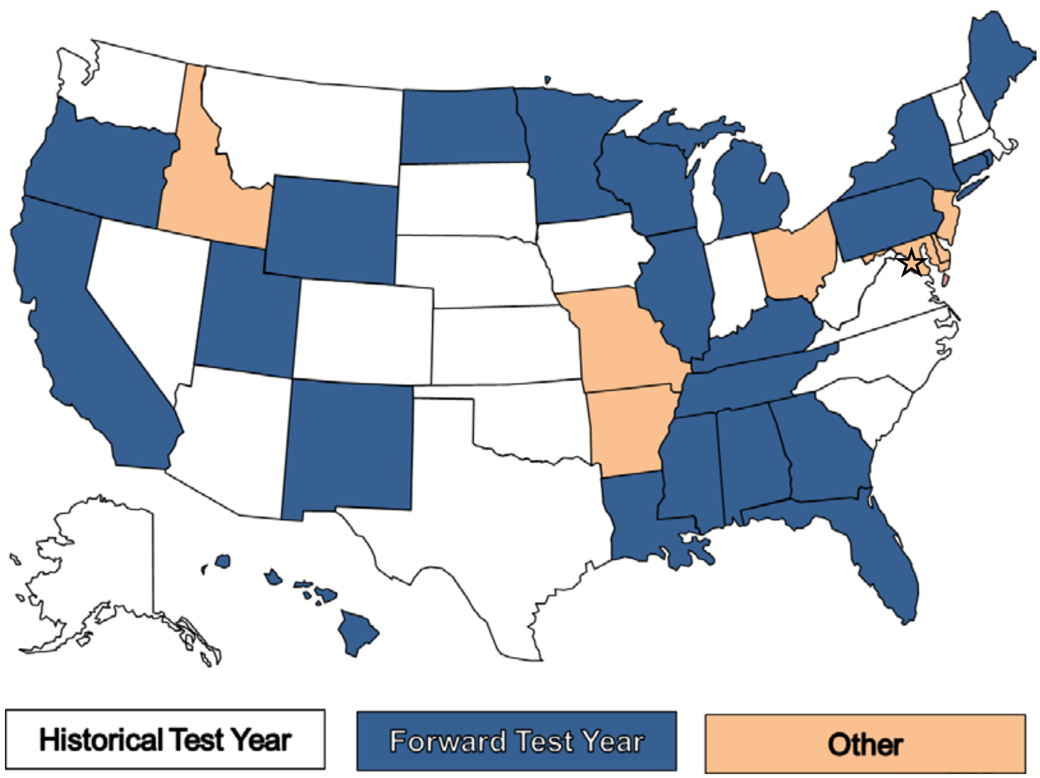
[4] A forward test year can in principle be the rate case year, and thereby not require two-year forecasts. Proposed rates can be established on an interim basis shortly after the filing.

[5] For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, Edison Electric Institute, 2010.

Because of these complications, we have separated Table 6 into separate sections, specifying where FTYs are commonly used or occasionally used. Figure 7 shows jurisdictions where FTYs are commonly or occasionally used. Jurisdictions where partially-forecasted test years are commonly or occasionally used are in the category titled Other, with the remaining jurisdictions counted as historical test years.

The ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total. Since our 2013 survey, electric utilities in Pennsylvania have successfully used FTYs and utilities in Arkansas and Indiana have received legislative authorization for their use.[6] [7] Forward test years are the norm in Canadian regulation.

Figure 7: Test Year Policy by State




[6] In addition, another electric utility in Mississippi was recently permitted to use a forward-looking formula rate plan.

[7] FTYs in Arkansas can only be used in formula rate plans.

Table 6

# Test Year Approaches of US Jurisdictions

| Jurisdiction | Notes |
|---|---|
| **Fully-Forecasted Test Years Commonly Used (15)** | |
| Alabama | Utilities operate under forward-looking formula rate plans |
| California | |
| Connecticut | |
| FERC | Rate cases use forward test years but some formula rate plans use historical test years |
| Florida | |
| Georgia | |
| Hawaii | |
| Maine | |
| Michigan | |
| Minnesota | |
| New York | |
| Oregon | |
| Rhode Island | |
| Tennessee | |
| Wisconsin | |
| **Fully-Forecasted Test Years Occasionally Used (9)** | |
| Illinois | Utilities use various test years including forward test years ("FTYs") |
| Kentucky | Utilities use various test years including FTYs |
| Louisiana | Utilities use various test years including FTYs |
| Mississippi | Both electric utilities operate under forward-looking formula rate plans. Gas formula rate plans rely on historical test years ("HTYs"). |
| New Mexico | A recently passed law allows for use of FTYs, and at least one rate increase based on FTY evidence has been approved |
| North Dakota | Utilities use various test years including FTYs |
| Pennsylvania | Partially-forecasted test years have traditionally been the norm. However, a law allowing fully-forecasted test years passed in 2012 and several electric utility rate increases based on FTY evidence have been approved. |
| Utah | Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs. |
| Wyoming | Rocky Mountain Power has recently used FTYs |
| **Partially-Forecasted Test Years Commonly or Occasionally Used (8)** | |
| Arkansas | Utilities have typically used partially forecasted test years in rate cases. However, a recent bill authorized the use of formula rates with either historical or forecasted test periods. |
| Delaware | Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings |
| District of Columbia | PEPCO has filed rate cases using both hybrid and historical test years recently |
| Idaho | |
| Maryland | Utilities use various test years excluding FTYs |
| Missouri | Utilities have the option to file partially-forecasted test years |
| New Jersey | |
| Ohio | |
| **Historical Test Years Commonly Used (20)** | |
| Alaska | |
| Arizona | |
| Colorado | Utilities have filed FTY evidence. However, no FTY rates have yet been approved but a recent case made extraordinary HTY adjustments. |
| Indiana | A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has been approved for an energy utility to date |
| Iowa | |
| Kansas | |
| Massachusetts | |
| Montana | |
| Nebraska | Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs. |
| Nevada | |
| New Hampshire | |
| North Carolina | |
| Oklahoma | |
| South Carolina | |
| South Dakota | |
| Texas | |
| Vermont | |
| Virginia | |
| Washington | |
| West Virginia | |

# V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to reduce regulatory cost, while increasing the utility incentive for efficient operation. Rate cases are held infrequently, most often at three to five year intervals. Between rate cases, rate escalations are based on a combination of automatic attrition relief mechanisms ("ARMs") and cost trackers. The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth.

The "externalization" of ratemaking that ARMs and rate case moratoria achieve gives utilities more opportunity to profit from improved performance. Benefits of better performance can be shared between the utility and its customers. Performance incentives are strengthened despite streamlined regulation. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs can cap growth in rates (e.g., customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster customer use of the grid. Revenue caps are usually combined with revenue decoupling mechanisms, and are often favored where utilities must cope with declining average use and/or policymakers strongly encourage DSM.

Several approaches to ARM design are well-established. These include multiyear cost forecasts, indexing, and hybrids. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in other cost drivers like the number of customers served. A hybrid approach to ARM design was developed in the US that involves indexing of revenue for O&M expenses and forecasts for capital cost revenue.

The indexing approach to ARM design has been more common for UDCs because their cost growth is relatively gradual and predictable. Hybrid and forecasted ARMs have historically been more common for vertically integrated electric utilities because occasional major plant additions have given their cost trajectories more of a "stairstep" pattern. However, this pattern is becoming less common in an era when demand growth is slower and fewer large power plants are under construction. Some VIEUs operating under MRPs have separate ARMs for generation and distribution.

Cost trackers are often used in MRPs to address changes in business conditions that are difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. MRPs with "tracker/freeze" provisions for vertically integrated utilities often accord tracker treatment to costs of new or refurbished generating plants.[8] Trackers also address *force majeure* events like severe storms and changes in tax rates that affect costs.

Many MRPs feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some MRPs feature "off-ramps" that permit plan suspension when earnings are unusually high or low.

[8] A good example is the Generation Base Rate Adjustment in the current MRP of Florida Power & Light.

Plans often feature performance incentive mechanisms that are linked to the utility's service quality. With stronger cost containment incentives, there is a greater need for a link between revenue and service quality. Many MRPs combine revenue decoupling, the tracking of DSM expenses, and performance incentives for DSM. The stronger incentive to contain cost that MRPs provide then becomes a "fourth leg" for the DSM stool.

MRPs have long been used to regulate utilities where market-responsive rates and services are a priority. Infrequent rate cases reduce the regulatory cost of allocating the revenue requirement between a complex and changing mix of market offerings and lessen concerns about cross-subsidization. These benefits of MRPs can be enhanced by designing other plan provisions in ways that insulate core customers from potentially adverse consequences of marketing flexibility.

For example, in the early 1990s, Maine's electric utilities were still vertically integrated and needed flexibility in marketing power to paper and pulp customers, some of whom had cogeneration options. The commission, under the chairmanship of Thomas Welch (a former telecom industry lawyer) approved a succession of price cap plans for Central Maine Power which facilitated marketing flexibility. As a result, the company had more freedom to enter into special contracts. The stronger incentives the company had to offer the right discounts to customers at risk of bypass was acknowledged by the commission when costs were allocated in later rate cases.

MRPs were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies. A major attraction was the ability of MRPs to afford utilities flexibility in serving markets with diverse competitive pressures and complex, changing customer needs. US and Canadian precedents for MRPs in the electricity and gas utility industries are indicated in Table 7 and Figures 8a and 8b.[9] In the US, MRPs have traditionally been most common in California and the Northeast. MRPs have been adopted by well-known VIEUs in Florida, North Dakota, and Virginia since our 2012 survey. A number of states have, additionally, experimented with "mini-MRPs" with terms of only two years. The forecast and tracker/freeze approaches to ARM design are most common currently in the US. The Federal Energy Regulatory Commission ("FERC") uses MRPs with index-based ARMs to regulate oil pipelines.

Canada is moving towards MRPs with index-based ARMs for gas and electric power distribution in all four populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Britain, and New Zealand are long time practitioners.

[9] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from Table 7 and Figures 8a and 8b.

Figure 8a: Recent US Multiyear Rate Plan Precedents by State

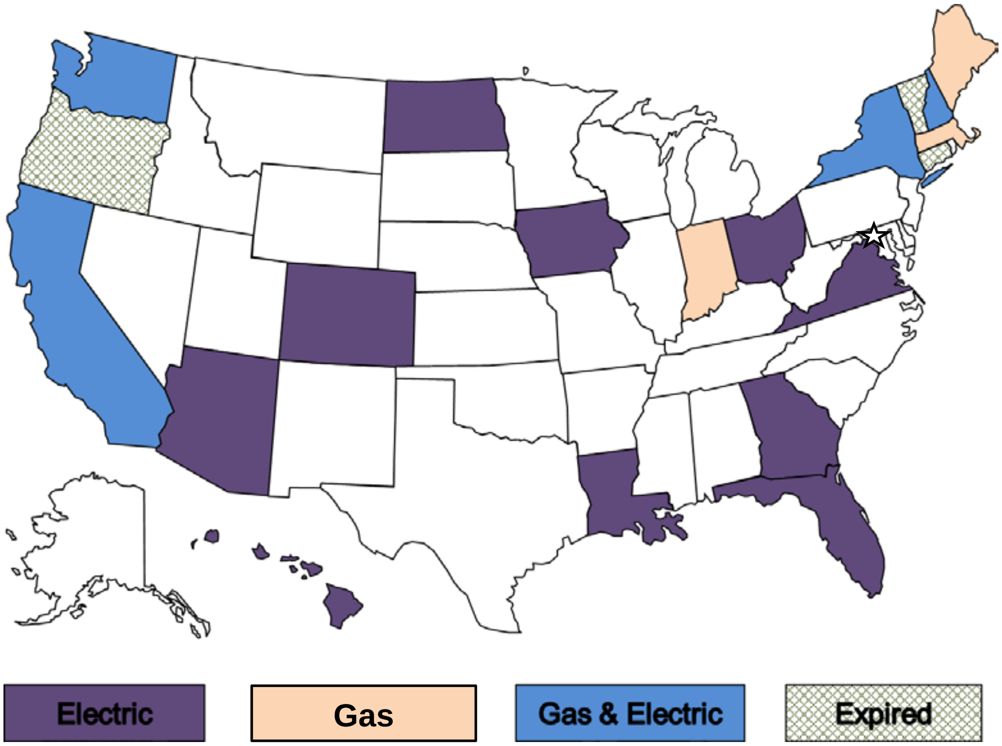



Figure 8b: Recent Canadian Multiyear Rate Plan Precedents by Province

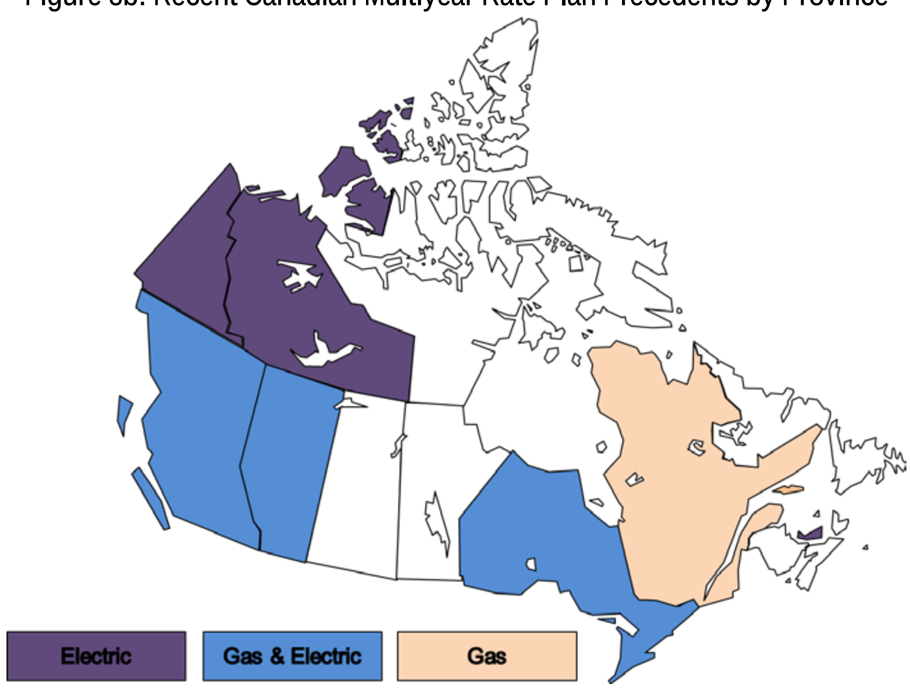


Table 7

# Multiyear Rate Plan Precedents [1]

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Current** | | | | | | |
| **United States** | | | | | | |
| AZ | Arizona Public Service | 2012-2016 | Bundled power service | Rate Freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capital and other cost trackers, LRAM | None | Decision 73183; May 2012 |
| CA | Bear Valley Electric Service | 2013-2016 | Power distribution | Revenue Cap Stairstep | None | Decision 14-11-002; November 2014 |
| CA | California Pacific Electric | 2013-2015 | Power distribution | Revenue Cap Index | None | Decision 12-11-030; November 2012 |
| CA | Pacific Gas & Electric | 2014-2016 | Gas & bundled power service | Revenue Cap Stairstep | None | Decision 14-08-032; August 2014 |
| CA | PacifiCorp | 2011-2013, extended through 2016 | Bundled power service | Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings | None | Decision 10-09-010; September 2010 |
| CA | San Diego Gas & Electric | 2012-2015 | Gas & bundled power service | Revenue Cap Stairstep | None | Decision 13-05-010; May 2013 |
| CA | Southern California Gas | 2012-2015 | Gas | Revenue Cap Stairstep | None | Decision 13-05-010; May 2013 |
| CA | Southwest Gas | 2014-2018 | Gas | Revenue Cap Stairstep | None | Decision 14-06-028; June 2014 |
| CO | Public Service of Colorado | 2015-2017 | Bundled power service | Rate Freeze with multiple capital cost trackers | Sharing of overearnings only up to earnings cap | Decision C15-0292; March 2014 |
| FL | Florida Power & Light | 2013-2016 | Bundled power service | Rate Freeze with multiple capital and other cost trackers | None | Docket 120015-EI; December 2012 |
| FL | Gulf Power | 2014-June 2017 | Bundled power service | Price Cap Stairstep through 2015, Rate Freeze beyond | None | Docket 130140-EI; December 2013 |
| FL | Duke Energy Florida (formerly Progress Energy Florida) | 2012-2016, extended through 2018 | Bundled power service | Rate Freeze with one step plus capital and other cost trackers | None | Dockets 120022-EI and 130208-EI; 2012 and November 2013 |
| FL | Tampa Electric | 2013-2017 | Bundled power service | Revenue Cap Stairstep | None | Docket 130040-EI |
| GA | Georgia Power | 2014-2016 | Bundled power service | Revenue Cap Stairstep | Sharing of overearnings only with deadband | Docket 36989; December 2013 |
| HI | Hawaiian Electric Company | 2012-open | Bundled power service | Revenue Cap Hybrid | Sharing of overearnings only without deadband, multiple sharing levels | Dockets 2008-0274 & 2008-0083 |
| HI | Hawaiian Electric Light Company | 2013-open | Bundled power service | Revenue Cap Hybrid | Sharing of overearnings only without deadband, multiple sharing levels | Dockets 2008-0274 & 2009-0164 |
| HI | Maui Electric | 2013-open | Bundled power service | Revenue Cap Hybrid | Sharing of overearnings only without deadband, multiple sharing levels | Dockets 2008-0274 & 2009-0163 |
| IA | MidAmerican Energy | 2014-2017 | Bundled power service | Revenue Cap Stairstep for 2014-2016, Rate Freeze for 2017 | Sharing of overearnings only with deadband up to earnings cap | RPU-2013-0004 |
| IN | Northern Indiana Public Service Company | 2015-2020 | Gas | Rate Freeze with capital and other cost trackers, possible reopening in 2017 | Earnings cap implemented if company overearns since last rate case or prior 59 months, whichever is less | Cause 43894 and 44403 TDSIC 1 (August 2013 and January 2015) |
| LA | Cleco Power | 2014-2017 | Bundled power service | Rate Freeze with capital and other cost trackers | Sharing of overearnings only with deadband up to earnings cap | Docket U-32779; June 2014 |
| MA | Bay State Gas | 2015-2018 | Gas | Revenue Cap Stairstep for 2015, 2016, Revenue Freeze through October 2018 | None | DPU 15-150; October 2015 |
| ME | Summit Natural Gas of Maine | 2013-2022 | Gas | Price Cap Indexing: 75% of change in GDPPI | None until company has 1,000 or more customers, then sharing of under/overearnings evenly with deadband | Docket 2012-258; January 2013 |
| NH | Northern Utilities | May 2014 - April 2017 | Gas | Revenue Cap Stairstep for 2014-2015, Rate Freeze in 2016 | Sharing of overearnings only with deadband up to earning cap | DG 13-086; April 2014 |
| NH | Public Service Company of New Hampshire | 2010-2015 | Power distribution (generation regulated separately) | Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013 | Sharing of overearnings only with deadband | DE 09-035 |
| NH | Unitil Energy Systems | 2011-2016 | Power distribution | Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013 | Sharing of overearnings only with deadband | DE 10-055 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Current** (cont'd) | | | | | | |
| **United States** (cont'd) | | | | | | |
| NY | Central Hudson Gas & Electric | 2015-2018 | Gas & power distribution | Revenue Cap Stairstep | Sharing of overearnings with deadband and multiple sharing bands | Cases 14-E-0318, 14-G-0319 |
| NY | Consolidated Edison | 2014-2016 | Gas | Revenue Cap Stairstep | Sharing of overearnings only with deadband and multiple bands | Case 13-G-0031 |
| NY | Corning Natural Gas | 2012-2015 | Gas | Revenue Cap Stairstep | Sharing of overearnings only with deadband and multiple bands | Case 11-G-0280 |
| NY | Orange & Rockland Utilities | November 2015-October 2018 | Gas | Revenue Cap Stairstep | Sharing of overearnings only with deadband and multiple sharing bands | Case 14-G-0494 |
| ND | Northern States Power - Minnesota | 2013-2016 | Bundled power service | Revenue Cap Stairstep for 2013-2015, Rate Freeze in 2016 | Sharing of overearnings only without deadband, earnings adjusted for effects of weather | Case PU-12-813 |
| OH | First Energy Ohio | 2011-2014, later extended to 2016 | Power distribution | Rate Freeze supplemented by capital and other cost trackers | Company subject to Significantly Excessive Earnings Test conducted annually | Cases 11-388-EL-SSO, 12-1230-EL-SSO |
| US | All | 2011-2016 | Oil pipelines | Price Cap Index: PPI-Finished Goods + 2.65% | None | Docket RM10-25-000; December 2010 |
| VA | Appalachian Power | 2014-2017 | Bundled power service | Rate Freeze supplemented by capital and other cost trackers | None | Senate Bill 1349 |
| VA | Virginia Electric Power | 2015-2019 | Bundled power service | Rate Freeze supplemented by capital and other cost trackers | None | Senate Bill 1349 |
| WA | Puget Sound Energy | 2013-2016 | Gas & bundled power service | Revenue Cap Stairstep | Sharing of overearnings only without deadband, equal sharing between company and customers | Dockets UE-121697 and UG-121705 |
| **Canada** | | | | | | |
| Alberta | Altagas Utilities and ATCO Gas | 2013-2017 | Gas | Revenue per Customer Indexing: Input price index - 1.16%, + capital cost trackers | None | Decision 2012-237 |
| Alberta | ATCO Electric, EPCOR, Fortis Alberta | 2013-2017 | Power distribution | Price Cap Index: Input Price Index - 1.16%, + capital cost trackers | None | Decision 2012-237 |
| British Columbia | FortisBC | 2014-2018 | Bundled power service | Revenue Cap Index: I-Factor - 1.03%, + capital cost tracker for CPCN projects | Symmetric without deadband | Project #3698719, Decision; September 2014 |
| British Columbia | FortisBC Energy | 2014-2018 | Gas | Revenue Cap Index: I-Factor - 1.1%, + capital cost tracker for CPCN projects | Symmetric without deadband | Project #3698715, Decision; September 2014 |
| Ontario | All unless company opts out | 2014-2018 | Power distribution | Price Cap Index: Input price index - (0%+stretch); stretch factor reassigned annually, + capital cost tracker option available | None | EB-2010-0379 Report of the Board; November 2013 |
| Ontario | Horizon Utilities | 2015-2019 | Power distribution | Revenue Cap Stairstep | Sharing of overearnings only without deadband | EB-2014-0002; December 2014 |
| Ontario | Hydro One Networks | 2015-2017 | Power distribution | Revenue Cap Stairstep | None | EB-2014-0247; March 2015 |
| Ontario | Enbridge Gas Distribution | 2014-2018 | Gas | Revenue Cap Stairstep | Sharing of overearnings only without deadband | EB-2012-0459, Decision with Reasons; July 2014 |
| Ontario | Union Gas Limited | 2014-2018 | Gas | Revenue Cap Index: 40% of growth in GDP-IPI | Sharing of overearnings only with deadband, multiple sharing ranges | EB 2013-0202 Decision; October 2013 |
| Prince Edward Island | Maritime Electric | 2013-2016 | Bundled power service | Price Cap Stairstep: Bill defines rates for each year. | Earnings cap set at allowed ROE, no floor | Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act |
| Quebec | Gazifere | 2011-2015 | Gas distribution | Price Cap Index | Sharing of overearnings only without deadband and multiple sharing bands up to earnings cap | D-2010-112; August 2010 |
| Yukon Territory | Yukon Electrical Company, Limited | 2013-2015 | Bundled power service | Revenue Cap Stairstep | None | Board Order 2014-06; April 2014 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Current (cont'd)** | | | | | | |
| **Great Britain** | | | | | | |
| Great Britain | All | 2013-2021 | Gas and power transmission | British-Style Hybrid | Not reviewed | RIIO-T1 Final Proposals, April and December 2012 |
| Great Britain | All | 2013-2021 | Gas distribution | British-Style Hybrid | Not reviewed | RIIO-GD1 Final Proposals, December 2013 |
| Great Britain | All | 2015-2023 | Power distribution | British-Style Hybrid | Variances of cost from budgets shared though Information Quality Incentive Mechanism | RIIO-ED1 Final Proposals, December 2014 |
| **Australia/New Zealand** | | | | | | |
| Australia | ActewAGL | 2015-2019 | Power transmission & distribution | Australian-Style Hybrid | Not reviewed | Final Decision ActewAGL distribution determination 2015-16 to 2018-19; April 2015 |
| Australia | Ausgrid | 2015-2019 | Power distribution | Australian-Style Hybrid | Not reviewed | Final Decision Ausgrid distribution determination 2015-16 to 2018-19; April 2015 |
| Australia | Directlink | 2015-2020 | Power transmission | Australian-Style Hybrid | Not reviewed | Final Decision Directlink transmission determination 2015-16 to 2019-20; April 2015 |
| Australia | Endeavour Energy | 2015-2019 | Power distribution | Australian-Style Hybrid | Not reviewed | Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19; April 2015 |
| Australia | Energex | 2015-2020 | Power distribution | Australian-Style Hybrid | Not reviewed | Final Decision Energex determination 2015-16 to 2019-20 |
| Australia | Ergon Energy | 2015-2020 | Power distribution | Australian-Style Hybrid | Not reviewed | Final Decision Ergon Energy determination 2015-16 to 2019-20 |
| Australia | Essential Energy | 2015-2019 | Power distribution | Australian-Style Hybrid | Not reviewed | Final Decision Essential Energy distribution determination 2015-16 to 2018-19; April 2015 |
| Australia | Jemena Gas Networks | 2015-2020 | Gas distribution | Australian-Style Hybrid | Not reviewed | Final Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015−20; June 2015 |
| Australia | SA Power Networks | 2015-2020 | Power distribution | Australian-Style Hybrid | Not reviewed | Final Decision SA Power Networks determination 2015-16 to 2019-20 |
| Australia | TasNetworks | 2015-2019 | Power transmission | Australian-Style Hybrid | Not reviewed | Final Decision TasNetworks transmission determination 2015-16 to 2018-19; April 2015 |
| Australia | TransGrid | 2015-2018 | Power transmission | Australian-Style Hybrid | Not reviewed | Final Decision TransGrid transmission determination 2015-16 to 2017-18; July 2015 |
| Australia | Power & Water | 2014-2019 | Power transmission & distribution | Australian-Style Hybrid | Not reviewed | 2014 Networks Price Determination Final Determination Part-A Statement of Reasons; April 2014 |
| Australia | All Queensland Distributors | 2011-2016 | Gas distribution | Australian-Style Hybrid | Not reviewed | Access Arrangement Proposal for Qld Gas Network, Final Decision; June 2011 |
| Australia | Energex and Ergon Energy | 2010-2015 | Power distribution | Australian-Style Hybrid | Not reviewed | Queensland Distribution Determination 2011-11 to 2014-15 (Final Decision) |
| Australia | Envestra | 2011-2016 | Gas distribution | Australian-Style Hybrid | Not reviewed | Access Arrangement Proposal for the SA Gas Network, Final Decision; June 2011 |
| Australia | All Victorian Distributors | 2013-2017 | Gas distribution | Australian-Style Hybrid | Not reviewed | Access Arrangement Final Decision; March 2013 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Current** (cont'd) | | | | | | |
| **Australia/New Zealand (cont'd)** | | | | | | |
| Australia | CitiPower | 2011-2015 | Power distribution | Australian-Style Hybrid | Not reviewed | CitiPower Pty Distribution Determination 2011-2015; September 2012 |
| Australia | Powercor | 2011-2015 | Power distribution | Australian-Style Hybrid | Not reviewed | Powercor Australia Ltd Distribution Determination 2011-2015; October 2012 |
| Australia | Jemena Electricity Networks | 2011-2015 | Power distribution | Australian-Style Hybrid | Not reviewed | Jemena Electricity Networks (Victoria) Ltd Distribution Determination 2011-2015; September 2012 |
| Australia | SP AusNet | 2011-2015 | Power distribution | Australian-Style Hybrid | Not reviewed | SPI Electricity Pty Ltd Distribution Determination 2011-2015; August 2013 |
| Australia | United Energy Distribution | 2011-2015 | Power distribution | Australian-Style Hybrid | Not reviewed | United Energy Distribution Distribution Determination 2011-2015; September 2012 |
| New Zealand | All but Orion Electric | 2015-2020 | Power distribution | Revenue Cap Index: CPI-0% for most companies | None | Project no. 14.07/14118; November 2014 |
| New Zealand | All | 2013-2017 | Gas distribution | New Zealand-Style Hybrid | Not reviewed | Project no. 15.01/13199 |
| New Zealand | All | 2013-2017 | Gas transmission | New Zealand-Style Hybrid | Not reviewed | Project no. 15.01/13199 |
| **Historic** | | | | | | |
| **United States** | | | | | | |
| CA | Bear Valley Electric Service | 2009-2012 | Power distribution | Revenue Cap Stairstep | None | Decision 09-10-028; October 2009 |
| CA | Pacific Gas & Electric | 2011-2013 | Gas & bundled power service | Revenue Cap Stairstep | None | Decision 11-05-018; May 2011 |
| CA | Pacific Gas & Electric | 2007-2010 | Gas & bundled power service | Revenue Cap Stairstep | None | Decision 07-03-044; March 2007 |
| CA | Pacific Gas & Electric | 2004-2006 | Gas & bundled power service | Revenue Cap Index | None | Decision 04-05-055; May 2004 |
| CA | Pacific Gas & Electric | 1993-1995 | Gas & bundled power service | Revenue Cap Hybrid | None | Decision 92-12-057; December 1992 |
| CA | Pacific Gas & Electric | 1990-1992 | Gas & bundled power service | Revenue Cap Hybrid | None | Decision 89-12-057; December 1989 |
| CA | Pacific Gas & Electric | 1987-1989 | Gas & bundled power service | Revenue Cap Hybrid | None | Decision 86-12-092; December 1986 |
| CA | Pacific Gas & Electric | 1984-1986 | Gas & bundled power service | Revenue Cap Hybrid | None | Decisions 83-12-068; December 1983 and 85-12-076; December 1985 |
| CA | PacifiCorp | 2007-2009, extended to 2010 | Bundled power service | Price Cap Index | None | Decisions 06-12-011; December 2006 and 09-04-017; April 2009 |
| CA | PacifiCorp | 1994-1996 | Bundled power service | Price Cap Index | None | Decision 93-12-106; December 1993 |
| CA | PacifiCorp | 1984-1987 | Bundled power service | Revenue Cap Hybrid | None | Decisions 84-07-150; July 1984 and 85-12-076; December 1985 |
| CA | San Diego Gas & Electric | 2008-2011 | Gas & bundled power service | Revenue Cap Stairstep | None | Decision 08-07-046; July 2008 |
| CA | San Diego Gas & Electric | 2005-2007 | Gas & bundled power service | Revenue Cap Index | Sharing of overearnings only with deadband and multiple sharing bands | Decision 05-03-025; March 2005 |
| CA | San Diego Gas and Electric | 1999-2002 | Gas & power distribution | Price Cap Index | Sharing of overearnings only above deadband with multiple sharing bands | Decision 99-05-030; May 1999 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | | |
| **United States** (cont'd) | | | | | | |
| CA | San Diego Gas & Electric | 1994-1999 | Gas & bundled power service | Revenue Cap Hybrid | Sharing of overearnings only with deadband and multiple sharing bands up to an earnings cap | Decision 94-08-023; August 1984 |
| CA | San Diego Gas & Electric | 1989-1993 | Gas & bundled power service | Revenue Cap Hybrid | None | Decision 88-12-085; December 1988 |
| CA | San Diego Gas & Electric | 1986-1988 | Gas & bundled power service | Revenue Cap Hybrid | None | Decision 85-12-108; December 1985 |
| CA | Sierra Pacific Power | 2009-2011, extended to 2012 | Bundled power service | Price Cap Index | None | Decision 09-10-041; October 2009 |
| CA | Sierra Pacific Power | 1990-1992 | Bundled power service | Revenue Cap Hybrid | None | Decision 90-07-060; July 1990 |
| CA | Southern California Edison | 2012-2014 | Bundled power service | Revenue Cap Hybrid | None | Decision 12-11-051; November 2012 |
| CA | Southern California Edison | 2009-2011 | Bundled power service | Revenue Cap Stairstep | None | Decision 09-03-025; March 2009 |
| CA | Southern California Edison | 2006-2008 | Bundled power service | Revenue Cap Hybrid | None | Decision 06-05-016; May 2006 |
| CA | Southern California Edison | 2004-2006 | Bundled power service | Revenue Cap Hybrid | None | Decision 04-07-022; July 2004 |
| CA | Southern California Edison | 1997-2001 | Power distribution | Price Cap Index | Sharing of over/underearnings outside deadband with multiple sharing bands | Decision 96-09-092; September 1996 |
| CA | Southern California Edison | 1986-1991 | Bundled power service | Revenue Cap Hybrid | None | Decision 85-12-076; December 1985 |
| CA | Southern California Gas | 2008-2011 | Gas | Revenue Cap Stairstep | None | Decision 08-07-046; July 2008 |
| CA | Southern California Gas | 2005-2007 | Gas | Revenue Cap Index | Sharing of overearnings only with deadband and multiple sharing bands | Decision 05-03-025; March 2005 |
| CA | Southern California Gas | 1998-2003 | Gas | Revenue Cap Index | Sharing of over/underearnings outside deadband with multiple sharing bands | Decision 97-07-054; July 1997 |
| CA | Southern California Gas | 1990-1993 | Gas | Revenue Cap Hybrid | None | Decision 90-01-016; January 1990 |
| CA | Southern California Gas | 1985-1989 | Gas | Revenue Cap Hybrid | None | 1984, 85-12-076; December 1985, and 87-05-027; May 1987 |
| CA | Southwest Gas | 2009-2013 | Gas | Revenue Cap Stairstep | None | Decision 08-11-048; November 2008 |
| CO | Public Service Company of Colorado | 2012-2014 | Bundled power service | Revenue Cap Stairstep | Sharing of overearnings only without deadband, multiple sharing bands up to earnings cap | Decision C12-0494 |
| CT | Connecticut Light & Power | 2004-2007 | Power distribution | Revenue Cap Stairstep | Even sharing of overearning without deadband | Docket 03-07-02 |
| CT | United Illuminating | 2006-2008 | Power distribution | Revenue Cap Stairstep | Even sharing of overearning without deadband | Docket 05-06-04 |
| FL | Florida Power & Light | 2006-2009 | Bundled power service | Rate Freeze with exception for new generating facilities after they are in service and multiple capital and other cost trackers | None | Docket 050045-EI |
| FL | Progress Energy Florida | 2006-2009 | Bundled power service | Rate Freeze with 1 step to reflect generation brought in-service and multiple capital and other cost trackers | None | Docket 050078-EI |
| GA | Georgia Power | 2011-2013 | Bundled power service | Revenue Cap Stairstep: Rate increases permitted for DSM and major generation plant additions | Sharing of overearnings only with deadband | Docket 31958 |
| IA | MidAmerican Energy | 2001-2005, extended to 2013 | Bundled power service | Rate Freeze with nuclear capital and other cost trackers | Sharing of overearnings only in multiple sharing bands, deadband not applicable due to no allowed ROE | Dockets RPU-01-3 and RPU-2012-0001 |
| LA | Cleco Power | 2009-2014 | Bundled power service | Rate Freeze with capital cost tracker | Sharing of overearnings only with deadband up to earnings cap | Order U-30689 |
| MA | Bay State Gas | 2006-2015, terminated in 2009 | Gas distribution | Price Cap Index | 75-25 shareholders-ratepayers sharing around deadband | Docket DTE 05-27 |
| MA | Berkshire Gas | February 2002-January 2012 | Gas distribution | No adjustment until September 2004, then Price Cap Index | None | Docket D.T.E. 01-56 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Attrition Relief Mechanism | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | | |
| **United States** (cont'd) | | | | | | |
| MA | Boston Gas (I) | 1997-2001 | Gas distribution | Price Cap Index | 75-25 shareholders-ratepayers sharing around deadband | Docket D.P.U. 96-50-C (Phase I); May 1997 |
| MA | Boston Gas (II) | 2004-2013, Terminated in 2010 | Gas distribution | Price Cap Index | 75-25 shareholders-ratepayers sharing around deadband | Docket DTE 03-40 |
| MA | Blackstone Gas | November 1, 2004 - October 31, 2009 | Gas distribution | Price Cap Index | Even sharing of earnings above/below deadband | Docket D.T.E. 04-79 |
| MA | Nstar | 2006-2012 | Power distribution | Price Cap Index | Deadband with 50-50 sharing of over and underearnings | Docket D.T.E. 05-85 |
| ME | Bangor Gas | 2000-2009, extended to 2012 | Gas distribution | Price Cap Index | Even sharing of overearnings only. No allowed ROE established for company and no determination of a deadband. | Docket 970795; June 1998 |
| ME | Bangor Hydro Electric (I) | 1998-2000 | Power distribution | Price Cap Index | 50/50 sharing around deadband | Docket 97-116; March 1998 |
| ME | Central Maine Power (I) | 1995-1999 | Bundled power service | Price Cap Index | Even sharing of earnings above/below deadband | Docket 92-345 Phase II; January 1995 |
| ME | Central Maine Power (II) | 2001-2007 | Power distribution | Price Cap Index | 50-50 sharing below deadband | Docket 99-666; November 2000 |
| ME | Central Maine Power (III) | 2009-2013 | Power distribution | Price Cap Index: GDPPI - 1%, separate capital cost tracker for AMI | 50-50 sharing above 11% ROE | Docket 2007-215 |
| ME | Maine Natural Gas | 2010-2012 | Gas | Revenue Cap Stairstep with steps conditioned on company earnings | None | Docket 2009-67 |
| NY | Brooklyn Union Gas | October 1, 1991 - September 30, 1994 | Gas | Revenue Cap Stairstep | Sharing of overearnings only without deadband | Case 90-G-0981, Opinion 91-21; October 1991 |
| NY | Brooklyn Union Gas | October 1, 1994 - September 30, 1997 | Gas | Revenue Cap Stairstep | Sharing of overearnings only without deadband and multiple sharing bands | Case 93-G-0941, Opinion 94-22; October 1994 |
| NY | Central Hudson Gas & Electric | 2010-2013 | Gas & power distribution | Revenue Cap Stairstep | Sharing of overearnings with deadband and multiple sharing bands | Case 09-E-0588 |
| NY | Central Hudson Gas & Electric | July 1, 2006 - June 30, 2009 | Gas & power distribution | Price Cap Stairstep | Sharing of overearnings only with deadband, multiple sharing bands up to earnings cap | Case 05-E-0934 & Case 05-G-0935; July 2006 |
| NY | Consolidated Edison | 2010-2013 | Gas | Revenue Cap Stairstep | Sharing of overearnings only with deadband that varies annually and multiple sharing bands | Case 09-G-0795 |
| NY | Consolidated Edison | 2007-2010 | Gas | Revenue Cap Stairstep | Even sharing of overearnings only above deadband, sharing threshold adjustable depending on work with DSM program administrator for first year only | Case 06-G-1332 |
| NY | Consolidated Edison | October 1, 1994 - September 30, 1997 | Gas | Revenue Cap Stairstep | Even sharing of overeearnings only above deadband | Case 93-G-0996, Opinion 94-2; October 1994 |
| NY | Consolidated Edison | 2010-2013 | Power distribution | Revenue Cap Stairstep | Sharing of overearnings only above deadband with multiple sharing bands | Case 09-E-0428 |
| NY | Consolidated Edison | April 1, 2005 - March 31, 2008 | Power distribution | Price Cap Stairstep | Sharing of overearnings only with multiple bands. No allowed ROE approved. | Case 04-E-0572; March 2005 |
| NY | Consolidated Edison | 1992-1995 | Bundled power service | Revenue Cap Stairstep | Even sharing of overearnings with varying allowed ROE and no deadband | Opinion 92-8 |
| NY | Keyspan Energy Delivery - Long Island | 2010-2012 | Gas | Revenue Cap Stairstep | Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance | Case 06-G-1185 |
| NY | Keyspan Energy Delivery - New York | 2010-2012 | Gas | Revenue Cap Stairstep | Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance | Case 06-G-1186 |
| NY | Long Island Lighting Company | December 1, 1993- November 30, 1996 | Gas | Revenue Cap Stairstep | Even sharing of overearnings only with deadband | Case 93-G-002, Opinion 93-23; December 1993 |
| NY | Long Island Lighting Company | 1992-1994 | Bundled power service | Revenue Cap Stairstep | Even sharing of overearnings only without deadband | Opinion 92-8 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Attrition Relief Mechanism | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | | |
| **United States** (cont'd) | | | | | | |
| NY | New York State Electric & Gas | 2010-2013 | Gas & power distribution | Revenue Cap Stairstep | Sharing of overearnings only with deadband that varies annually and multiple sharing bands | Case 09-E-0715 |
| NY | New York State Electric & Gas | August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring | Bundled power service | Revenue Cap Stairstep | Sharing of overearnings only with annually varying deadbands | Case 94-M-0349, Opinion 95-27; September 1995 |
| NY | New York State Electric & Gas | December 1, 1993 - August 31, 1995 | Gas & bundled power service | Revenue Cap Stairstep | Even sharing of overearnings only above deadband | Case 92-G-1086, Opinion 93-22; November 1993 |
| NY | Niagara Mohawk | July 1, 1990 - December 31, 1992 | Gas & bundled power service | Revenue Cap Stairstep | Sharing of overearnings only without deadband up to earnings cap | Case 29327, Opinion 89-37; June 1991 |
| NY | Orange & Rockland Utilities | 2009-2012 | Gas | Revenue Cap Stairstep | Sharing of overearnings only beyond deadband and multiple sharing bands | Case 08-G-1398 |
| NY | Orange & Rockland Utilities | November 1, 2006 - October 31, 2009 | Gas | Price Cap Stairstep | Sharing of overearnings only beyond deadband and multiple sharing bands | Case 05-G-1494; October 2006 |
| NY | Orange & Rockland Utilities | November 1, 2003- October 31, 2006 | Gas | Price Cap Stairstep | Even sharing of overearnings only without deadband | Case 02-G-1553; October 2003 |
| NY | Orange & Rockland Utilities | 2012-2015 | Power distribution | Revenue Cap Stairstep | Sharing of overearnings only with deadband and multiple bands | Case 11-E-0408 |
| NY | Orange & Rockland Utilities | 2008-2011 | Power distribution | Revenue Cap Stairstep | Sharing of overearnings only above deadband with multiple sharing bands | Case 07-E-0949 |
| NY | Orange & Rockland Utilities | 1991-1993 | Bundled power service | Revenue Cap Stairstep | Even sharing of overearnings above deadband | Case 89-E-175 |
| NY | Rochester Gas & Electric | 2010-2013 | Gas & power distribution | Revenue Cap Stairstep | Sharing of overearnings only with deadband that varies annually and multiple sharing bands | Case 09-E-0717 |
| NY | Rochester Gas & Electric | July 1, 1993 - June 30, 1996 | Gas & bundled power service | Revenue Cap Stairstep | Earnings cap only | Case 92-G-0741, Opinion No. 93-19; August 1993 |
| OH | AEP-Ohio | 2012-2015 | Power distribution | Rate Freeze supplemented by capital and other cost trackers | Company subject to Significantly Excessive Earnings Test conducted annually | Case No. 11-346-EL-SSO; August 2012 |
| OH | Cincinnati Gas & Electric | 2009-2011 | Power generation | Price Cap Stairstep | Company subject to Significantly Excessive Earnings Test conducted annually | Case 08-920-EL-SSO |
| OR | PacifiCorp | 1998-2001 | Power distribution | Revenue Cap Index | Sharing of over/underearning outside deadband in multiple sharing bands | Order No. 98-191 |
| US | All | 2006-2011 | Oil pipelines | Price Cap Index: PPI-Finished Goods + 1.3% | None | RM05-22-000 |
| US | All | 2001-2006 | Oil pipelines | Price Cap Index: PPI-Finished Goods + 0% | None | RM00-11-000 |
| US | All | 1995-2001 | Oil pipelines | Price Cap Index: PPI-Finished Goods - 1% | None | RM93-11-000 |
| VT | Green Mountain Power | 2007-2010 | Bundled power service | Revenue Cap Stairstep | Earnings cap for overearnings above deadband; Multiple sharing bands for earnings apply if actual ROE below deadband (earnings floor of the deadband also applies) | Docket No. 7176 |
| WA | Puget Sound Energy | 1997-2001 | Bundled power service | Price Cap Stairstep | None | Docket UE-960195 |
| **Australia/New Zealand** | | | | | | |
| Australia | Jemena Gas Networks | 2010-2015 | Gas distribution | Australia-Style Hybrid | Not reviewed | Access Arrangement Proposal for NSW Gas Networks, Final Decision; June 2010 |
| Australia | All New South Wales distributors | 2009-2014 | Power distribution | Australia-Style Hybrid | Not reviewed | New South Wales Distribution Determination 2009-10 to 2013-14 Final Decision |
| Australia | ElectraNet | 2008-2013 | Power transmission | Australia-Style Hybrid | Not reviewed | Final Decision; April 2008 |
| Australia | ElectraNet | 2003-2008 | Power transmission | Australia-Style Hybrid | Not reviewed | File No: C2001/1094 |
| Australia | Powerlink | 2007-2012 | Power transmission | Australia-Style Hybrid | Not reviewed | Final Decision; June 2007 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | | |
| **Australia/New Zealand (cont'd)** | | | | | | |
| Australia | Powerlink | 2002-2007 | Power transmission | Australia-Style Hybrid | Not reviewed | File No: 2000/659 |
| Australia | Snowy Mountains | 1999-2004 (terminated in 2002 due to merger with Transgrid) | Electric transmission | Australia-Style Hybrid | Not reviewed | File No: C1999/62 |
| Australia | SPI PowerNet | 2003-2008 | Power transmission | Australia-Style Hybrid | Not reviewed | File No: C2001/1093 |
| Australia | Transend | 2009-2014 | Power transmission | Australia-Style Hybrid | Not reviewed | Transend Transmission Determination 2009/10-2013/14 (Final Decision) |
| Australia | Transend | 2004-2009 | Power transmission | Australia-Style Hybrid | Not reviewed | File No: C2001/1100 |
| Australia | Transgrid | 2009-2014 | Electric transmission | Australia-Style Hybrid | Not reviewed | Transgrid Transmission Determination 2009/10-2013/14 (Final Decision) |
| Australia | Transgrid | 2004-2009 | Power transmission | Australia-Style Hybrid | Not reviewed | File No. M2003/287 |
| Australia | Transgrid | 1999-2004 | Power transmission | Australia-Style Hybrid | Not reviewed | File No: CG98/118 |
| Australia- New South Wales | Country Energy Gas | 2006-2010 | Gas distribution | Australia-Style Hybrid | Not reviewed | Revised Access Arrangement for Country Energy Gas Network, Final Decision; November 2005 |
| Australia- New South Wales | AGL Gas Networks | 1999-2004 | Gas transmission & distribution | Australia-Style Hybrid | Not reviewed | Access Arrangement for AGL Gas Networks Limited, Final Decision; July 2000 |
| Australia - New South Wales | All | 2004-2009 | Power distribution | Australia-Style Hybrid | Not reviewed | File No: S2004/138 |
| Australia - New South Wales | All | 1999-2004 | Power distribution | Australia-Style Hybrid | Not reviewed | NEC Determination 99-1 |
| Australia - Northern Territory | Power & Water | 2000-2003 | Power transmission & distribution | Australia-Style Hybrid | Not reviewed | Revenue Determinations document; June 2000 |
| Australia - Northern Territory | Power & Water | 2009-2014 | Power transmission & distribution | Price Cap Index: CPI + 0.85% | Not reviewed | Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009 |
| Australia - Northern Territory | Power & Water | 2004-2009 | Power transmission & distribution | Price Cap Index: CPI - 2% | Not reviewed | Final Determination Networks Pricing: 2004 Regulatory Reset; February 2004 |
| Australia -Victoria | All | 2008-2012 | Gas distribution | Australia-Style Hybrid | Not reviewed | Gas Access Arragement Review 2008-2012, Final Decision; March 2008 |
| Australia -Victoria | All | 2003-2007 | Gas distribution | Australia-Style Hybrid | Not reviewed | Review of Gas Access Arrangements, Final Decision; October 2002 |
| Australia -Victoria | All | 2006-2010 | Power distribution | Australia-Style Hybrid | Not reviewed | Electricity Distribution Price Review 2006-2010 (Final Decision Volume 1) |
| Australia -Victoria | All | 2001-2005 | Power distribution | Australia-Style Hybrid | Not reviewed | Electricity Distribution Price Determination 2001-2005 (Final Decision Volume 1) |
| New Zealand | All | 2010-2015 | Power distribution | Revenue Cap Index: CPI - 0% | None | Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | | |
| **Australia/New Zealand (cont'd)** | | | | | | |
| New Zealand | All | 2004-2009 | Power distribution | Revenue Cap Index: CPI - 0.86% (Average across firms) | None | Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003 |
| **Canada** | | | | | | |
| Alberta | Enmax | 2007-2013 | Power distribution | Price Cap Index: Input Price Index -1.2% | 50-50 for excess earnings above deadband | Decision 2009-035 |
| Alberta | Northwestern Utilities | 1999-2002, reopened for 2001-2002 | Gas distribution | Revenue Cap Stairstep; at reopener replaced with rate freeze | Sharing of earnings above/below deadband with multiple bands for overearnings; at reopener simplified to 50/50 sharing of overearnings with deadband | Decision U98060; March 1998 and Decision 2000-85; December 2000 |
| Alberta | EPCOR | 2002-2005, Terminated 12/31/2003 | Power distribution | Price Cap Index | None | City of Edmonton Distribution Tariff Bylaw 12367; August 2000 |
| Northwest Territory | Northland Utilities | 2011-2013 | Bundled power service | Revenue Cap Stairstep | None | Decision 17-2011; November 2011 |
| Northwest Territory | Northland Utilities (Yellowknife) | 2011-2013 | Bundled power service | Revenue Cap Stairstep | None | Decision 13-2011; August 2011 |
| Ontario | All Ontario Distributors | 2010-2013 | Power distribution | Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies) | None | EB-2007-0673; July 2008, September 2008, and January 2009 |
| Ontario | All Ontario Distributors | 2006-2009 | Power distribution | Price Cap Index | None | EB-2006-0089; December 2006 |
| Ontario | All Ontario Distributors | 2000-2003 | Power distribution | Price Cap Index | 50-50 sharing of excess earnings without deadband | RP-1999-0034; January 2000 |
| Ontario | Enbridge Gas Distribution | 2008-2012 | Gas distribution | Revenue Cap Index: GDP-IPI * 53% | 50-50 sharing of excess earnings above deadband | EB-2007-0615; February 2008 |
| Ontario | Union Gas | 2008-2012 | Gas distribution | Revenue Cap Index: GDP-IPI -1.82% | Sharing of overearnings only with deadband and multiple sharing bands | EB-2007-0606; January 2008 |
| Ontario | Union Gas | 2001-2003 | Gas distribution | Price Cap Index | 50-50 sharing around deadband | RP-1999-0017; July 2001 |
| **Great Britain** | | | | | | |
| Great Britain | All | 2008-2013 | Gas distribution | British-Style Hybrid | Not reviewed | Review- Final Proposals; Published December 2007 |
| Great Britain | All | 2002-2007, extended to 2008 | Gas distribution | British-Style Hybrid | Not reviewed | "RPI - X @ 20." Ofgem Publication |
| Great Britain | All | 2007-2012 | Gas transmission | British-Style Hybrid | Not reviewed | Transmission Price Control Review; Published December 2006 |
| Great Britain | All | 2002-2007 | Gas transmission | British-Style Hybrid | Not reviewed | "RPI - X @ 20." Ofgem Publication |
| Great Britain | All | 1998-2002 | Gas transmission & distribution | British-Style Hybrid | Not reviewed | Energy Law Journal Volume 23 No. 2 p.444 |
| Great Britain | All | 1994-1997 | Gas transmission & distribution | British-Style Hybrid | Not reviewed | Energy Law Journal Volume 23 No. 2 p.444 |
| Great Britain | All | 1992-1994 | Gas transmission & distribution | British-Style Hybrid | Not reviewed | Energy Law Journal Volume 23 No. 2 p.444 |
| England & Wales | All | 1995-2000 | Power distribution | British-Style Hybrid | Not reviewed | "RPI - X @ 20." Ofgem Publication |
| Great Britain | All | 2010-2015 | Power distribution | British-Style Hybrid | Variances of cost from budgets shared though Information Quality Incentive Mechanism | Ofgem Distribution Price Control Review 5 |
| Great Britain | All | 2005-2010 | Power distribution | British-Style Hybrid | Not reviewed | Ofgem Distribution Price Control Review 4 |

Table 7 (cont'd)

| Jurisdiction | Company | Plan Term | Services Covered | Rate Escalation Provisions | Earnings Sharing Provisions | Case Reference |
|---|---|---|---|---|---|---|
| **Historic** (cont'd) | | | | | | |
| **Great Britain (cont'd)** | | | | | | |
| Great Britain | All | 2000-2005 | Power distribution | British-Style Hybrid | Not reviewed | "RPI - X @ 20." Ofgem Publication |
| England & Wales | National Grid | 2001-2006, extended to 2007 | Power transmission | British-Style Hybrid | Not reviewed | OECD Reviews of Regulatory Reform |
| England & Wales | National Grid | 1997-2001 | Power transmission | British-Style Hybrid | Not reviewed | "RPI - X @ 20." Ofgem Publication |
| England & Wales | National Grid | 1993-1997 | Power transmission | British-Style Hybrid | Not reviewed | Energy Law Journal Volume 23 No. 2 p.452 |
| Great Britain | All | 2007-2012 | Power transmission | British-Style Hybrid | Not reviewed | Transmission Price Control Review; Published December 2006 |
| Scotland | All | 2000-2005, extended to 2007 | Power transmission | British-Style Hybrid | Not reviewed | "RPI - X @ 20." Ofgem Publication |
| Scotland | All | 1995-2000 | Power transmission | British-Style Hybrid | Not reviewed | 1995 Report by Monopolies and Mergers Commission |

[1] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from this table.

# VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service. Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated. Regulatory cost is contained by limiting review of costs and revenues.

The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target. Both approaches can keep the utility whole for the time value of money.

Earning true up mechanisms often include a deadband in which variances don't trigger a rate adjustment. Once the variance exceeds the deadband, however, earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between the earnings true up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans.

Formula rates do not always address major plant additions. In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is often recovered through a separate tracker.

Mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its O&M expenses may be limited by a formula tied to an inflation index. FRPs in several states that include Illinois and Mississippi contain a number of targeted performance incentive mechanisms.

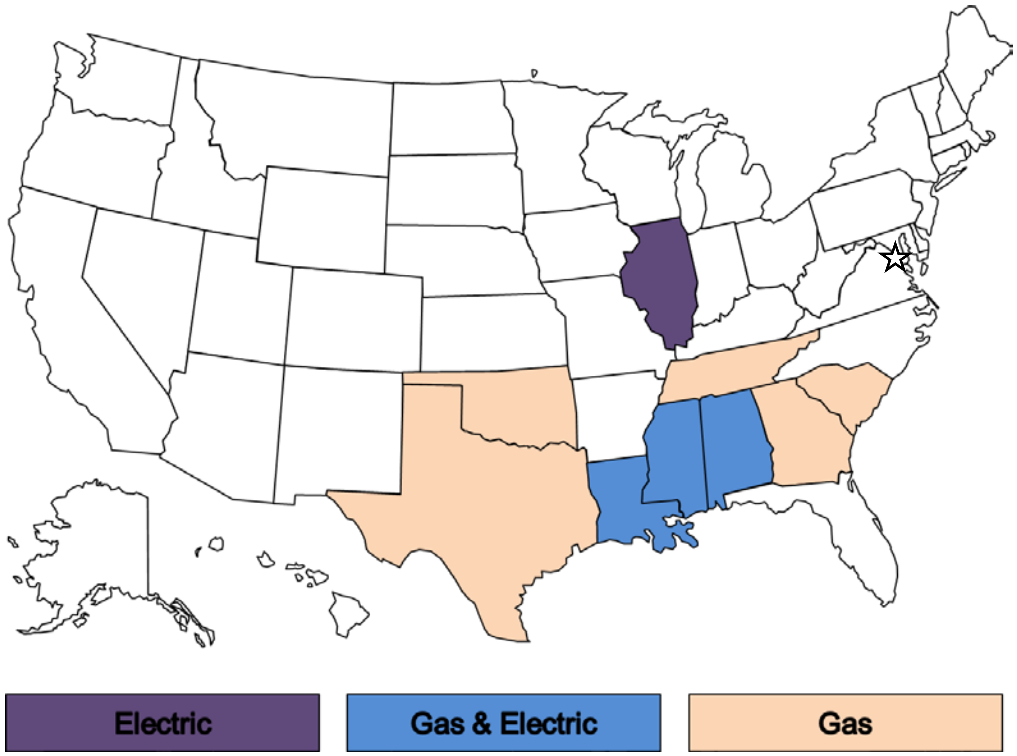
Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of energy utilities for decades. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 8 and Figure 9.[10] It can be seen that FRPs for retail utility services are most common in the Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization"

[10] Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition. These usually take the form of ESMs that may or may not protect the utility from underearning.

plans for Alabama Power and Alabama Gas in the early 1980s.[11] Formula rates are now used to regulate electric utilities in Illinois, some gas and electric utilities in Louisiana and Mississippi, and some gas utilities in Georgia, Oklahoma, South Carolina, Tennessee, and Texas. Most of the recent approvals of formula rates have been for gas distribution, as this is one means to avoid the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized legislatively for electric utilities in Arkansas.

Figure 9: Current Retail Formula Rate Precedents by State




[11] For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 8

# Retail Formula Rate Plan Precedents[1]

| Jurisdiction | Company Name | Services | Plan Name | Plan Term | Case Reference |
|---|---|---|---|---|---|
| **Current** | | | | | |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 2013-open | Dockets 18117 and 18416 (August 2013) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2014-2018 | Dockets 18406 and 18328 (December 2013) |
| AL | Mobile Gas Service | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2013-2017 | Docket 28101 (August 2013) |
| GA | Atmos Energy | Gas | Georgia Rate Adjustment Mechanism (GRAM) | 2012-open | Docket 34764 (December 2011) |
| IL | Ameren Illinois | Power Distribution | Rate Modernization Action Plan - Pricing (Rate MAP-P) | 2011-2017, extended through 2019 | Case 12-0001 (September 2012) and Public Act 098-1175 |
| IL | Commonwealth Edison | Power Distribution | Rate Delivery Service Pricing and Performance (Rate DSPP) | 2011-2017, extended through 2019 | Case 11-0721 (May 2012) and Public Act 098-1175 |
| LA | Atmos Energy - Louisiana Gas Service | Gas | Rate Stabilization Clause | 2014-open | Docket U-32987 (June 2014) |
| LA | Atmos Energy - Trans Louisiana Gas | Gas | Rate Stabilization Clause | 2014-open | Docket U-32987 (June 2014) |
| LA | Southwestern Electric Power | Electric | Formula Rate Plan | 2013-2016 | Docket U-32220 (July 2014) |
| MS | Atmos Energy Corp | Gas | Stable/Rate Rider | 2011-present | Docket 05-UN-0503 (April 2011) |
| MS | Centerpoint Energy | Gas | Rate Regulation Adjustment Rider | 2014-open | Docket 2014-UN-060 (May 2014) |
| MS | Entergy Mississippi | Bundled Power Service | Formula Rate Plan 6 (FRP-6) | 2015-open | Docket 2014-UN-132 (December 2014) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 5 (PEP-5) | 2010-open | Docket 2003-UN-0898 (November 2009) |
| OK | Centerpoint Energy Arkla | Gas | Performance Based Rate of Change Plan | 2010-open | Cause PUD 201000030 (July 2010) |
| OK | Arkansas Oklahoma Gas | Gas | Performance Based Rate of Change Plan | 2013-open | Cause PUD 201200236 (July 2013) |
| SC | Piedmont Gas | Gas | NA | 2005-open | Docket 2005-125-G (September 2005) |
| SC | South Carolina Electric and Gas | Gas | NA | 2005-open | Docket 2005-113-G (October 2005) |
| TN | Atmos Energy | Gas | Annual Review Mechanism | 2015-open | Docket 14-00146 (May 2015) |
| TX | Centerpoint Energy-Texas Coast Division | Gas | Cost of Service Adjustment Clause | 2008-open | Gas Utility Docket 9791 (October 2008) |
| TX | Atmos Energy-Mid Texas Division | Gas | Rate Review Mechanism | 2013-2017 | Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2007 |
| TX | Atmos Energy West Texas Division | Gas | Rate Review Mechanism | 2014-open | Various Resolutions/Ordinances across cities in service territory including City of Tulia Ordinance 2014-03 |
| TX | Texas Gas Service - Rio Grande Service Area | Gas | Cost of Service Adjustment | 2012-open | Various Resolutions/Ordinances across cities in service territory |
| TX | Texas Gas Service - North Service Area | Gas | Cost of Service Adjustment Tariff | 2009-open | Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009) |

# Table 8 (cont'd)

| Jurisdiction | Company Name | Services | Plan Name | Plan Term | Case Reference |
|---|---|---|---|---|---|
| **Historic** | | | | | |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 2006-2013 | Dockets 18117 and 18416 (October 2005) |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 2002-2006 | Dockets 18117 and 18416 (March 2002) |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 1998-2002 | Dockets 18117 and 18416 (March 1998) |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 1990-1998 | Dockets 18117 and 18416 (March 1990) |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 1985-1990 | Dockets 18117 and 18416 (June 1985) |
| AL | Alabama Power | Bundled Power Service | Rate Stabilization & Equalization Factor (Rate RSE) | 1982-1985 | Dockets 18117 and 18416 (November 1982) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2008-2014, later changed to 2013 | Dockets 18406 and 18328 (December 2007) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2002-2007 | Dockets 18046 and 18328 (June 2002) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 1996-2001 | Dockets 18046 and 18328 (October 1996) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 1991-1995 | Dockets 18046 and 18328 (December 1990) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 1987-1990 | Dockets 18046 and 18328 (September 1987) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 1985-1987 | Dockets 18046 and 18328 (May 1985) |
| AL | Alabama Gas | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 1983-1985 | Dockets 18046 and 18328 (January 1983) |
| AL | Mobile Gas Service | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2009-2013 | Docket 28101 (December 2009) |
| AL | Mobile Gas Service | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2005-2009 | Docket 28101 (June 2005) |
| AL | Mobile Gas Service | Gas | Rate Stabilization & Equalization Factor (Rate RSE) | 2001-2005 | Docket 28101 (June 2002) |
| LA | Atmos Energy - Louisiana Gas Service | Gas | Rate Stabilization Plan | 2006-2014 | Docket U-21484 (May 2006) |
| LA | Atmos Energy - Louisiana Gas Service | Gas | Rate Stabilization Plan | 2001-2003 | Docket U-21484 (January 2001) |
| LA | Atmos Energy - Trans Louisiana Gas | Gas | Rate Stabilization Plan | 2006-2014 | Dockets U-28814 and U-28588 and U-28587(May 2006) |
| LA | Entergy New Orleans | Electric and Gas | Formula Rate Plan | 2010-2012 | Docket UD-08-03 (April 2009) |
| LA | Entergy New Orleans | Electric only | Formula Rate Plan | 2004-2006 | Docket UD-01-04 (May 2003) |
| MS | Atmos Energy Corp | Gas | Stable/Rate Rider | 2009-2011 | Docket 05-UN-0503 (December 2009) |
| MS | Atmos Energy Corp | Gas | Stable/Rate Rider | 2006-2009 | Docket 05-UN-0503 (October 2005) |
| MS | Atmos Energy Corp | Gas | Stable/Rate Rider | 1992-2006 | Docket 92-UA-0230 (September 1992) |
| MS | Centerpoint Energy | Gas | Rate Regulation Adjustment Rider | 2012-2014 | Docket 12-UN-139 (May 2012) |

# Table 8 (cont'd)

| Jurisdiction | Company Name | Services | Plan Name | Plan Term | Case Reference |
|---|---|---|---|---|---|
| **Historic (cont'd)** | | | | | |
| MS | Centerpoint Energy Entex | Gas | Rate Regulation Adjustment Rider | 2008-2012 | Docket 07-UN-548 (December 2007) |
| MS | Centerpoint Energy Entex | Gas | Rate Regulation Adjustment Rider | 1996-2007 | Docket 96-UN-0202 (September 1996) |
| MS | Entergy Mississippi | Bundled Power Service | Formula Rate Plan 5 (FRP-5) | 2010-2014 | Docket 2009-UN-388 (March 2010) |
| MS | Entergy Mississippi | Bundled Power Service | Formula Rate Plan 1 (FRP-1) | 1995 | Docket 93-UA-0301 (March 1994) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 4A (PEP- 4A) | 2009 | Docket 06-UN-0511 (January 2009) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 4 (PEP-4) | 2004-2009 | Docket 03-UN-0898 (May 2004) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 3 (PEP-3) | 2002-2004 | Docket 01-UN-0826 (October 2002) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 2A (PEP-2A) | 2001-2002 | Docket 01-UN-0548 (December 2001) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 1A (PEP-1A) | 1992-1993 | Docket 92-UN-0059 (July 1992) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan - 1 (PEP-1) | 1991-1992 | Docket 90-UN-0287 (December 1990) |
| MS | Mississippi Power | Bundled Power Service | Performance Evaluation Plan | 1986-1990 | Cause PUD U-4761 (August 1986) |
| OK | Centerpoint Energy Arkla | Gas | Performance Based Rate of Change Plan | 2008-2010 | Cause PUD 200800062 (July 2008) |
| OK | Centerpoint Energy Arkla | Gas | Performance Based Rate of Change Plan | 2004-2008 | Cause PUD 200400187 (November 2004) |
| OK | Oklahoma Natural Gas | Gas | Performance Based Rate of Change Plan | 2010-2014 | Docket 200800348 (April 2009) |
| TX | Atmos Energy-Mid Texas Division | Gas | Rate Review Mechanism | 2008 - varying end dates | Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008 |
| TX | Atmos Energy West Texas Division | Gas | Rate Review Mechanism | 2009 - conclusion of rate case to be filed on or before June 1, 2013 | Various Resolutions/Ordinances across cities in service territory |
| TX | Centerpoint Energy - Beaumont East Texas Gas Division | Gas | Cost of Service Adjustment | 2009-2011 | Various Resolutions/Ordinances across cities in service territory |
| TX | Texas Gas Service - Rio Grande Service Area | Gas | Cost of Service Adjustment | 2009-2011 | Various Resolutions/Ordinances across cities in service territory |

[1] Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

# VII. Marketing Flexibility

This is a new section, added since the last survey. We've added it because we (and EEI) believe that marketing flexibility is a growing, strategic issue for EEI members. Several trends in business conditions are driving the need for more flexibility. The growth of distributed energy resources, for example, is a competitive challenge but also brings new service opportunities related to the development of distributed energy assets (e.g., designing, financing, procuring, building, fueling, and maintaining). Grid modernization is providing new functional capabilities to the grid which also create new service opportunities.[12] Examples include new reliability, network management, and transaction management services. Residential and commercial customers also have a growing interest in plug-in electric vehicles, and all retail customers have shown an interest in green power packages that can be supplied from grid-accessed resources.

New services will tend to be optional services that all customers will not want. Customers must be able to decline them; and if they do, not to incur associated costs. Competitive alternatives will be available for many of these services, and customers may have special needs that are difficult to address with standard tariffs. Thus, utilities will need to be able to respond quickly to the market. They will often be price "takers," as opposed to price "makers."

To date, regulatory precedent allowing investor-owned electric utilities to offer many of these services has been limited. This chapter is, in effect, a place holder for expected future electricity precedent.

### Why Electric Utilities Need Marketing Flexibility

Of course, electric utilities have always needed flexibility in some of the markets they serve:

- Utility assets have uses in markets other than those for retail electric services. Most notably, surplus generating capacity of VIEUs can be used for sales in bulk power markets. These markets are competitive and price-volatile. Land in transmission corridors can be well-suited for nurseries. Prices utilities charge in competitive markets like these are largely decontrolled. Margins earned in these markets are shared with customers of retail electric services.
- The demand of large-load retail customers is often sensitive to the rates and other terms of service utilities offer because these customers have power-intensive technologies and/or options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Customers of this kind are especially important to vertically integrated utilities. Discounts or special contracts for such customers are traditionally allowed but often require specific approval. Commission reviews of special contracts can take months.

[12] For an overview of modernization, see: EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, 2014.

### Marketing Flexibility Remedies

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to “light handed” regulation and outright decontrol. Light handed regulation typically takes the form of expedited approval of market offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

Flexibility is most commonly granted for rates and services with certain characteristics. Light handed regulation of optional rates and services, for example, is based on the grounds that customers are protected by their freedom not to take the service, their continued access to service under standard tariffs, and the availability of alternatives in unregulated markets. Optional offerings include tariffs open to all qualifying customers, special contracts, and discretionary value-added services. Decontrol is typically permitted only for offerings to markets where vigorous competition reigns.

### Marketing Flexibility Examples: Electric Utilities

Marketing flexibility is not extensive in the electric utility industry today but there are nonetheless notable examples such as the following.

- Four Florida electric utilities have “Commercial/Industrial Service Rider” (“CISR”) tariffs that allow them to negotiate contract service agreements (“CSAs”) that outline discounts on the base energy and/or demand charges for large load customers who can show that they have viable alternatives to utility-provided electric service.[13] The discounted rate must cover the incremental cost of service provision and provide a contribution to fixed costs. CSAs do not need commission approval but the commission has the option to conduct a prudence review of any signed contract.

- Duke Energy offers large North Carolina customers an optional Green Source Rider service. The program allows customers that have added at least 1 MW of new load since June 2012 to apply for an annual amount of renewable energy (and the associated renewable energy certificates) over a specific term (between 3-15 years). Customers may request a particular renewable resource in their application. Duke would then negotiate a purchased power agreement on behalf of the customer or attempt to source the energy from its own assets.

[13] Florida Public Service Commission (2014), Order Approving Commercial/Industrial Service Rider Tariff, Order No. PSC-14-0110-TRF-EI.

## Marketing Flexibility in Other Regulated Industries

Regulators and electric utilities considering new forms of marketing flexibility can learn from other utility industries that have experienced technological change, increased competition, and/or complex and changing customer needs. We provide here brief overviews of experience in the telecommunications, gas distribution, gas transmission, and railroad industries.

### Telecommunications

Local telephone companies (aka incumbent local exchange carriers or "ILECs") control the traditional distribution networks connecting residences and businesses. The "last mile" services they provide include the interconnection needed for long-distance, data, security, paging, and mobile telephone services as well as local telephone calling. ILECs have in the last 30 years confronted extensive competition, rapid technological change, and new marketing opportunities. Challenges they have faced have many parallels to those emerging for electric utilities.

The Federal Communications Commission ("FCC") regulates interstate access services of ILECs. Other ILEC services are regulated by state commissions. In the 1980s, ILECs were still regulated using cost-of-service regulation with complex reporting and compensation schemes. This was succeeded by multiyear rate plans, often called "price cap" plans since they capped rate escalation but permitted some discounts to encourage greater system use. Price caps were often escalated using inflation – X formulas where the X factor reflected an estimate of the telecommunication industry productivity trend. Prices were separately capped for several baskets of services. This insulated customers in each service basket from discounts offered to other baskets. Insulation was heightened by the infrequency (or elimination) of rate cases and the common lack of earnings sharing. The FCC instituted price caps for interstate access services of ILECs in the early 1990s. Price caps also became commonplace in state ILEC regulation.

Marketing flexibility for ILECs has been most relevant in the following two areas.

Competition in Traditional Service Markets Some services ILECs offered became subject to mounting competitive pressure that varied with the location where service was offered. For example, by the late 1990s, competitive access providers like MFS were constructing high-speed fiber optic networks connecting office buildings in metropolitan areas. These networks allowed businesses and long-distance carriers to connect to customers while bypassing ILEC data facilities. They could also be used to transmit voice traffic, avoiding ILEC voice access charges. High regulated prices were uncompetitive in high-traffic locations where facilities-based competitors entered the market. For services subject to competitive challenges, price cap plans in many states permitted discounts to standard tariffs within certain bands (e.g., rates could rise by 5% less than the price cap index) and/or subject to pricing floors that discouraged predation and cross-subsidization. In markets where pronounced competition could be demonstrated, ILEC rates were sometimes effectively decontrolled.

Innovative Services Technological change gave rise to innovative new services [e.g., Voicemail, Centrex and high-speed data (e.g., digital subscriber loop or "DSL")] which utilize essential network assets of ILECs and cannot not practically be performed by affiliates.[14] Many of these services were deemed "information" services and were regulated by the FCC. Regulators ultimately permitted ILECs to provide a host of these services and allowed considerable pricing flexibility.

Gas Distribution

Natural gas distributors also need flexibility to address some markets that they serve. Like VIEUs, many large-load customers of gas distributors have price sensitive demands and special needs. Distributors have frequently obtained light handed regulation to respond to these challenges. Nicor Gas, for example, offers a contract service for customers taking delivery near interstate gas pipelines. Contracts are submitted to state regulators for informational purposes and are treated on a proprietary basis. Nicor has similar flexibility to enter into custom contracts with electric power generators. The Company must document to the regulator that revenues from such service exceed the incremental cost of service, thereby ensuring a positive contribution to fixed cost recovery.

Interstate Gas Transmission

Interstate pipeline companies need marketing flexibility for many reasons. Demand for a pipeline's services can be sensitive to the terms it offers due to competition from other pipelines, dual-fuel capabilities of large volume customers, the extreme variability of need for service, and other special needs. It is difficult to design standard tariffs that meet the needs of all customers. Pipelines also have their own needs, such as an interest in signing anchor shippers to long-term contracts before constructing new facilities. Since 1996, the FERC has engaged in light handed regulation of negotiated pipeline rates to individual customers who have recourse to service under a standard tariff. The FERC gives a quick turnaround to most requests for negotiated contracts. A sizable share of pipeline service is conducted under negotiated rates. A remarkable variety of rate designs have been employed.[15]

Railroads

In the railroad industry, MRPs were permitted under the terms of the Staggers Railroad Act of 1980. Railroads were given a freer hand to respond to competition from truckers, waterborne carriers, and other railroads. The railroads also used marketing flexibility to offer discounts to customers that reduced their cost by assembling their own unit trains and not requesting pickups or deliveries in remote locations.

MRPs are less common today in the railroad and telecom industries. However, marketing flexibility continues under new regulatory systems that share with MRPs the attribute of protecting core customers without linking a carrier's rates closely to its own cost. Railroads have recently used this flexibility to compete for traffic from new oil field developments.

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[14] Centrex service, which provided businesses features like call-waiting, auto attendant, voicemail, 4-digit extension dialing and conference calling, could also be sourced by purchasing or leasing a private branch exchange ("PBX"), a private network platform that enabled these features.

[15] See, for example, Comments of the Interstate Natural Gas Association of America in FERC Docket PLO2-6-000, September 2002.

# VIII. Conclusions

Regulation of North American energy utilities is evolving to better meet the needs of utilities and their customers in a rapidly changing world. Innovation continues, while some older forms of Altreg such as multiyear rate plans are having a renaissance.

The variety of Altreg approaches that have been established reflects the varied circumstances of utilities. Some are vertically integrated, while others are more specialized wire companies. Capex needs and trends in average use vary greatly. Regulatory traditions also vary across the US and other advanced industrial countries.

No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying challenges increases the chance that an approach has already been tried that would work well, with some adjustments, in new situations. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to achieve compensatory rates of return while making needed investments, improving efficiency, and developing more market-responsive rates and services. Regulation can be streamlined, and utilities can be encouraged to embrace cost-effective DERs. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which kinds of Altreg might work best in their situation.

**CERTIFICATE OF SERVICE**

I hereby certify that a copy of Potomac Electric Power Company's Comments has been served this November 1, 2019 on:

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